DTE Electric Company

Capital Expenditures and Rate Base

($000)

Line No.	Description	Historical 12 mos. ended 12/31/2013 [1]	Historical 12 mos. ended 12/31/2014 [2]	Historical 12 mos. ended 12/31/2015	Historical 12 mos. ended 12/31/2016 [3]	Historical 12 mos. ended 12/31/2017 [4]	Historical 12 mos. ended 12/31/2018 [5]
		(1)	(2)	(3)	(4)	(5)	(6)
1	Production Plant:						
2	Steam	350,266	351,992		311,663	248,162	189,349
3	Hydraulic	58,910	60,008		56,226	61,120	36,528
4	Other	1,190	2,875		18,556	58,953	149,669
5	MERC / Fuel Supply	3,041	3,168		4,529	5,660	4,027
6	Nuclear (including Nuclear Fuel)	186,126	117,674		229,109	161,187	240,334
7	Distribution	385,560	449,484		493,433	651,372	832,419
8	Customer Service and Regulated Marketing	13,179					
9	AMI	91,430	66,236		47,011		
10	Community Lighting		11,929		17,286	11,312	14,003
11	Demand Side Management		516		12,702	12,673	10,144
12	Information Technology					86,685	79,167
13	Corporate Staff	158,482	183,057		163,364	114,287	114,113
14	Charging Forward						
15	Customer 360	7,407	-	-	56,759	28,959	-
16	Total Capital Expenditures	**1,255,591**	**1,246,939**	**N/A**	**1,410,638**	**1,440,370**	**1,669,753**
17	Rate Base	**11,577,725**	**12,395,893**	**N/A**	**14,335,514**	**15,202,906**	**16,323,401**

Sources:

[1] Case No. U-17767, Exhibit A-9, Schedule B6, T.M. Uzenski, Case No. U-17767, Exhibit A-9, Schedule B1.1, M.A. Suchta.
[2] Case No. U-18014, Exhibit A-9, Schedule B6, T.M. Uzenski, Case No. U-18014, Exhibit A-9, Schedule B1.1, P.G. Horgan.
[3] Case No. U-18255, Exhibit A-9, Schedule B6, T.M. Uzenski, Case No. U-18255, Exhibit A-9, Schedule B1.1, K.L. Slater.
[4] Case No. U-20162, Exhibit A-12, Schedule B5, T.M. Uzenski, Case No. U-20162, Exhibit A-2, Schedule B1, K.L. Slater.
[5] Case No. U-20561, Exhibit A-12, Schedule B5, T.M. Uzenski, Case No. U-20561, Exhibit A-12, Schedule B1, M.A. Suchta.

DTE Electric

Earned vs. Authorized ROEs

Line	Month	Earned ROE %[1]	Authorized ROE %[2]	Rate Base ($000s)[2]	Authorized Equity Ratio[2]	Earned Weighted Cost	Authorized Weighted Cost	Tax Factor[3]	Difference in Pre-Tax Earned vs. Authorized Cost	Revenue Impact of Earned ROE ($000s)
1	Jan-18	10.1	10.1	15,296,281	37.5%	3.8%	3.8%	1.3496	0.0%	$ -
2	Feb-18	10.3	10.1	15,389,655	37.5%	3.9%	3.8%	1.3496	0.1%	$ 1,298
3	Mar-18	10.5	10.1	15,483,030	37.5%	3.9%	3.8%	1.3496	0.2%	$ 2,611
4	Apr-18	10.6	10.1	15,576,404	37.5%	4.0%	3.8%	1.3496	0.3%	$ 3,284
5	May-18	10.7	10.0	15,669,779	36.8%	3.9%	3.7%	1.3496	0.3%	$ 4,545
6	Jun-18	10.8	10.0	15,763,154	36.8%	4.0%	3.7%	1.3496	0.4%	$ 5,225
7	Jul-18	11.3	10.0	15,856,528	36.8%	4.2%	3.7%	1.3496	0.6%	$ 8,541
8	Aug-18	11.9	10.0	15,949,903	36.8%	4.4%	3.7%	1.3496	0.9%	$ 12,556
9	Sep-18	12.0	10.0	16,043,277	36.8%	4.4%	3.7%	1.3496	1.0%	$ 13,294
10	Oct-18	11.7	10.0	16,136,652	36.8%	4.3%	3.7%	1.3496	0.8%	$ 11,366
11	Nov-18	11.4	10.0	16,230,026	36.8%	4.2%	3.7%	1.3496	0.7%	$ 9,414
12	Dec-18	10.5	10.0	16,323,401	36.8%	3.9%	3.7%	1.3496	0.2%	$ 3,382
13	Average	11.0	10.0						Total	$ 75,516
14	Jan-17	10.8	10.3	14,407,797	38.0%	4.1%	3.9%	1.6393	0.3%	$ 3,743
15	Feb-17	10.5	10.1	14,480,079	37.5%	3.9%	3.8%	1.6393	0.2%	$ 2,966
16	Mar-17	10.4	10.1	14,552,362	37.5%	3.9%	3.8%	1.6393	0.2%	$ 2,236
17	Apr-17	10.4	10.1	14,624,645	37.5%	3.9%	3.8%	1.6393	0.2%	$ 2,247
18	May-17	10.4	10.1	14,696,927	37.5%	3.9%	3.8%	1.6393	0.2%	$ 2,258
19	Jun-17	10.3	10.1	14,769,210	37.5%	3.9%	3.8%	1.6393	0.1%	$ 1,513
20	Jul-17	10.1	10.1	14,841,493	37.5%	3.8%	3.8%	1.6393	0.0%	$ -
21	Aug-17	9.3	10.1	14,913,775	37.5%	3.5%	3.8%	1.6393	-0.5%	$ (6,110)
22	Sep-17	9.0	10.1	14,986,058	37.5%	3.4%	3.8%	1.6393	-0.7%	$ (8,443)
23	Oct-17	9.1	10.1	15,058,341	37.5%	3.4%	3.8%	1.6393	-0.6%	$ (7,712)
24	Nov-17	9.5	10.1	15,130,623	37.5%	3.6%	3.8%	1.6393	-0.4%	$ (4,649)
25	Dec-17	10.0	10.1	15,202,906	37.5%	3.7%	3.8%	1.6393	-0.1%	$ (779)
26	Average	10.0	10.1						Total	$ (12,730)
27	Jan-16	9.9	10.3	13,446,521	38.0%	3.8%	3.9%	1.6393	-0.2%	$ (2,794)
28	Feb-16	9.8	10.3	13,527,339	38.0%	3.7%	3.9%	1.6393	-0.3%	$ (3,514)
29	Mar-16	9.6	10.3	13,608,156	38.0%	3.7%	3.9%	1.6393	-0.4%	$ (4,949)
30	Apr-16	9.6	10.3	13,688,974	38.0%	3.7%	3.9%	1.6393	-0.4%	$ (4,978)
31	May-16	9.5	10.3	13,769,791	38.0%	3.6%	3.9%	1.6393	-0.5%	$ (5,723)
32	Jun-16	10.1	10.3	13,850,609	38.0%	3.8%	3.9%	1.6393	-0.1%	$ (1,439)
33	Jul-16	10.6	10.3	13,931,426	38.0%	4.0%	3.9%	1.6393	0.2%	$ 2,171
34	Aug-16	11.4	10.3	14,012,244	38.0%	4.3%	3.9%	1.6393	0.7%	$ 8,008
35	Sep-16	11.3	10.3	14,093,061	38.0%	4.3%	3.9%	1.6393	0.6%	$ 7,322
36	Oct-16	11.5	10.3	14,173,879	38.0%	4.4%	3.9%	1.6393	0.7%	$ 8,836
37	Nov-16	11.4	10.3	14,254,696	38.0%	4.3%	3.9%	1.6393	0.7%	$ 8,146
38	Dec-16	10.9	10.3	14,335,514	38.0%	4.1%	3.9%	1.6393	0.4%	$ 4,469
39	Average	10.5	10.3						Total	$ 15,554
40	Jan-15	10.5	10.5	12,476,711	40.3%	4.2%	4.2%	1.6394	0.0%	$ -
41	Feb-15	10.8	10.5	12,557,528	40.3%	4.3%	4.2%	1.6394	0.2%	$ 2,072
42	Mar-15	10.6	10.5	12,638,346	40.3%	4.3%	4.2%	1.6394	0.1%	$ 695
43	Apr-15	10.5	10.5	12,719,163	40.3%	4.2%	4.2%	1.6394	0.0%	$ -
44	May-15	10.4	10.5	12,799,981	40.3%	4.2%	4.2%	1.6394	-0.1%	$ (704)
45	Jun-15	9.8	10.5	12,880,798	40.3%	3.9%	4.2%	1.6394	-0.5%	$ (4,959)
46	Jul-15	10.4	10.5	12,961,616	40.3%	4.2%	4.2%	1.6394	-0.1%	$ (713)
47	Aug-15	10.3	10.5	13,042,433	40.3%	4.1%	4.2%	1.6394	-0.1%	$ (1,435)
48	Sep-15	11.0	10.5	13,123,251	40.3%	4.4%	4.2%	1.6394	0.3%	$ 3,609
49	Oct-15	10.5	10.5	13,204,068	40.3%	4.2%	4.2%	1.6394	0.0%	$ -
50	Nov-15	10.1	10.5	13,284,886	40.3%	4.1%	4.2%	1.6394	-0.3%	$ (2,923)
51	Dec-15	10.0	10.3	13,365,704	38.0%	3.8%	3.9%	1.6394	-0.2%	$ (2,083)
52	Average	10.4	10.5						Total	$ (6,441)
53	Jan-14	11.4	10.5	11,645,906	40.3%	4.6%	4.2%	1.6394	0.6%	$ 5,765
54	Feb-14	11.4	10.5	11,714,086	40.3%	4.6%	4.2%	1.6394	0.6%	$ 5,799
55	Mar-14	11.3	10.5	11,782,267	40.3%	4.5%	4.2%	1.6394	0.5%	$ 5,184
56	Apr-14	11.4	10.5	11,850,448	40.3%	4.6%	4.2%	1.6394	0.6%	$ 5,866
57	May-14	11.4	10.5	11,918,628	40.3%	4.6%	4.2%	1.6394	0.6%	$ 5,900
58	Jun-14	11.8	10.5	11,986,809	40.3%	4.8%	4.2%	1.6394	0.9%	$ 8,571
59	Jul-14	11.0	10.5	12,054,990	40.3%	4.4%	4.2%	1.6394	0.3%	$ 3,315
60	Aug-14	10.7	10.5	12,123,170	40.3%	4.3%	4.2%	1.6394	0.1%	$ 1,334
61	Sep-14	10.6	10.5	12,191,351	40.3%	4.3%	4.2%	1.6394	0.1%	$ 671
62	Oct-14	10.4	10.5	12,259,532	40.3%	4.2%	4.2%	1.6394	-0.1%	$ (674)
63	Nov-14	10.7	10.5	12,327,712	40.3%	4.3%	4.2%	1.6394	0.1%	$ 1,356
64	Dec-14	10.8	10.5	12,395,893	40.3%	4.3%	4.2%	1.6394	0.2%	$ 2,045
65	Average	11.1	10.5						Total	$ 45,131
66									Grand Total	$ 117,030

Sources:
[1]Quarterly Financial Report on Michigan Electric and Natural Gas Utilities.
[2]Exhibit AB-1.
[3]S&P Global Market Intelligence.
[4]Case Nos: U-20162, U-18255, and U-18014
Note:
In instances when the Rate Case Completion date occurs after the 16th of the month, updated Authorized ROE values used in following month.

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-2.1]
Respondent:	J. C. Davis
Page:	1 of 1

Question: In connection with the Nuclear Decommissioning Study ("Study") project for Fermi 2 shown on Line 23 of Exhibit A-13, Schedule C5.16, please name the entity that will be conducting that Study.

Answer: DTE Electric is performing the Fermi 2 Nuclear Decommissioning Study depicted on Exhibit A-13, Schedule C5.16, line 23. My direct testimony on JCD-32, line 1 through JCD-33, line 12 describes this Nuclear Decommissioning Study. Where appropriate, DTE Electric is using suppliers to accelerate the delivery of certain analytics such as the Fermi 2 site-specific inventory described on JCD-32 line 17 though line 23.

DTE Electric notes the Nuclear Decommissioning Study is different from and broader in scope than a decommissioning cost estimate (DCE).

Attachments: None

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-2.2 2nd Supplemental]
Respondent:	J. C. Davis/Legal
Page:	1 of 2

Question: If the Study is being provided by a third-party then provide the copy of the contract between DTE and the third-party.

Answer: Please refer to DTE Electric's response to ABDE-2.1.

DTE Electric Company objects for the reasons that the information requested consists of confidential, proprietary information, trade secrets and commercial information, the disclosure of which would cause DTE Electric Company, its vendors, and its customers competitive harm. Subject to and without waiving the above objections, DTE Electric further states:

DTE Electric reserves all rights to contest, move for reconsideration, and appeal the protective order issued in this proceeding on September 23, 2019 but, subject to and without waiving this reservation of rights, the Company is making available pursuant to the September 23, 2019 protective order, the contract between DTE Electric and the third-parties set forth in this supplemental response to those individuals who have properly executed a non-disclosure certificate under the September 23, 2019 protective order issued in this proceeding.

DTE Electric is using Energy Solutions LLC to calculate the Fermi 2 site-specific inventory and unit-work rates for the Fermi 2 site-specific decommissioning cost estimate (DCE). The projected expenditures associated with this service are bounded by the forecasted Nuclear Decommissioning Study expenditures described in my direct testimony at JDC-32, lines 12 – 15. After subsequent discussions, on October 22, 2019, Energy Solutions provided DTE Electric with approval to provide the unredacted agreement governing this service pursuant to protective order. Please see attachments labeled "U-20561 ABDE-2.2-01 4701349567 ES CO 1_NDA.pdf", "U-20561 ABDE-2.2-02 Ts Cs_Consulting Services_Rev. 052018_NDA" and "U-20561 ABDE-2.2-03 4701349567 Table 1_NDA".

DTE Electric is using Callan LLC to provide its reference documentation for Callan's upcoming 2019 edition of their Nuclear Decommissioning Funding Study. The projected expenditures associated with this service are bounded by the forecasted Nuclear Decommissioning Study expenditures described in my direct testimony at JDC-32, lines 12 – 15. Please see attachment "U-20561 ABDE-2.2 4701366352 Callan_NDA.pdf."

MPSC Case No.: U-20561
Requestor: ABATE
Question No.: ABDE-2.2 2nd Supplemental]
Respondent: J. C. Davis/Legal
Page: 2 of 2

Attachments:

Supplemental

U-20561 ABDE-2.2 4701366352 Callan_NDA.pdf
U-20561 ABDE-2.2-01 4701349567 ES CO 1_NDA.pdf
U-20561 ABDE-2.2-02 Ts Cs_Consulting Services_Rev. 052018_NDA
U-20561 ABDE-2.2-03 4701349567 Table 1_NDA

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-3.21a]
Respondent:	T. M. Uzenski
Page:	1 of 1

Question: Referring Exhibit A-12 Schedule B4.4, please answer the following questions:

a. Provide workpapers, in Microsoft Excel with all formulas intact, showing the development of the prepaid pension asset on an annual basis since December 31, 2002 and over the period where the prepaid asset balance was accumulated up through April 30, 2021. Please include in the calculation individual annual pension expense components (such as interest cost and administrative expense) and annual pension trust funding components (such as cash contributions and return on the asset).

Answer: See attached.

Attachments: *U-20561 ABDE-3.21a Prepaid Pension 2002-April 2021.xls*

DTE Electric Company
Prepaid Pension Asset ($000)

Case No.: U-20561
Discovery Request: ABDE-3.21a
Date Received: 10/4/2019
Witness: T. M. Uzenski

	Actual 2003	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012
Beginning Balance Asset/(Liability)	(37,563)	105,746	175,481	68,803	112,257	167,843	208,076	334,449	433,046	497,030
Less:										
Service Costs	40,103	47,387	52,962	49,261	48,760	43,046	40,859	49,466	53,389	62,973
Interest Costs	126,485	129,774	130,366	132,999	135,152	144,779	154,376	149,692	150,205	151,601
Expected Return on Assets	(128,822)	(134,653)	(135,125)	(135,625)	(147,585)	(163,353)	(164,812)	(171,544)	(168,288)	(165,639)
Amortizations										
(Gain)/Loss	32,010	49,001	50,012	44,259	44,152	24,743	36,506	68,567	96,370	120,807
Prior Service Costs	8,915	8,756	8,463	7,528	6,333	5,955	6,698	5,222	4,340	719
Special Termination Benefits	0	0	0	38,124	7,602	0	0	0	0	0
Total Expense	78,691	100,265	106,678	136,546	94,414	55,170	73,627	101,403	136,016	170,461
Plus: Funding	222,000	170,000	0	180,000	150,000	100,000	200,000	200,000	200,000	200,000
Retained Earnings Adjustment (1)	0	0	0	0	0	(4,597)	0	0	0	0
Ending Balance Asset/(Liability)	105,746	175,481	68,803	112,257	167,843	208,076	334,449	433,046	497,030	526,569

(1) Retained earning adjustment relates to change in measurement date from November 30 to December 31 in 2008, as required by SFAS 158

	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Actual 2018	Projected 2019	Projected 2020	Projected 4/30/2021	**12/31/2002 to 4/31/21**
Beginning Balance Asset/(Liability)	526,569	626,506	635,983	616,073	633,639	691,666	757,717	776,971	862,115	(37,563)
Less:										
Service Costs	71,928	63,145	75,456	69,170	68,813	73,239	62,116	59,762	19,090	1,050,925
Interest Costs	142,334	157,538	155,738	162,043	157,434	148,298	161,515	161,159	53,480	2,704,968
Expected Return on Assets	(184,661)	(194,123)	(210,258)	(219,641)	(222,242)	(235,148)	(233,552)	(234,676)	(78,603)	(3,328,350)
Amortizations										0
(Gain)/Loss	144,777	107,400	142,596	114,528	122,207	122,653	90,717	88,710	31,862	1,531,877
Prior Service Costs	685	1,563	1,378	1,334	761	(93)	(50)	(99)	(392)	68,016
Special Termination Benefits	0	0	0	0	0	0	0	0	0	45,726
Total Expense	175,063	135,523	164,910	127,434	126,973	108,949	80,746	74,856	25,437	2,073,162
Plus: Funding	275,000	145,000	145,000	145,000	185,000	175,000	100,000	160,000	0	2,952,000
Retained Earnings Adjustment (1)	0	0	0	0	0	0	0	0	0	(4,597)
Ending Balance Asset/(Liability)	626,506	635,983	616,073	633,639	691,666	757,717	776,971	862,115	836,678	836,678

April '2020	*752,019*
April '2021	*836,678*
Average Bal	**794,348**

Exhibit A-12 B4 Line 23: *12/31/2018 Bal* **757,717**

MPSC Case No.: U-20561
Requestor: ABATE
Question No.: ABDE-4.37f]
Respondent: R. Cejas Goyanes
Page: 1 of 2

Question: Referring to the direct testimony of Rodrigo Cejas Goyanes, please answer the following questions regarding the Company's demand response, or demand side management, portfolio:

f. Please confirm that the total demand response plant investment proposed to be included in rate base for the Test Year period in the instant proceeding is the same projected plant investment currently pending before the Commission in DTE's IRP proceeding, Case No. U-20471. If not confirmed, please explain, support, and justify all differences, and provide all analyses and workpapers relied upon to support the plant amounts.

Answer: The total demand response ("DR") capital expenditures forecasted and proposed for the test year period in the current rate case (U-20561) are different from the capital expenditures projected in the Company's IRP Case U-20471. It is important to note that the periods included in the DTE's IRP Case differ from the test year period in the general rate case U-20561. The amounts detailed in the table below are shown in thousand dollars.

	U-20561			U-20471		
Program/Pilot Description	**Calendar Yr. 2020**	**Calendar Yr. 2021**	**Total 2020-2021**	**Calendar Yr. 2020**	**Calendar Yr. 2021**	**Total 2020-2021**
IAC	1,762	5,000	6,762	1,800	5,000	6,800
PCT	462	-	462	3,700	3,000	6,700
Other DR Pilots	2,137	4,000	6,137	2,100	2,000	4,100
Subtotal	4,361	9,000	13,361	7,600	10,000	17,600
DTE Insight	843	3,031	3,874	n/a	n/a	n/a
Total	5,204	12,031	17,235	7,600	10,000	17,600

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-4.37f]
Respondent:	R. Cejas Goyanes
Page:	2 of 2

The main differences correspond to the following items:

- PCT: As indicated on page 19 in direct testimony of Witness Cejas Goyanes, the Company is planning to reach the goal of the 10,000-customer enrollment level by the end of 2019. The Company will then assess the success of the program before continuing enrollment of additional customers if appropriate. The corresponding capital expenditures to reach that level of 10,000 customers and complete full processing and integration of the newly enrolled customers through the end of the bridge period (April 30, 2020) are requested in the current Case U-20561. In the IRP case, the Company projected capital expenditures to invest in the enrollment of additional customers beyond the 10,000-enrollment goal.

- Other Pilots: The capital expenditure projection in Case U-20561 is consistent with the Company's updated plan to evaluate and execute on the development of various pilot opportunities. The updated plan includes for instance an expanded scope in the storage pilots and a recently considered peak-time rebate pilot.

- DTE Insight: The program is not included in the DTE's IRP Case U-20471. Even though the DTE Insight program aims at driving customer behavior to reduce electricity demand during peak hours, the Company does not measure the program as a supply resource for capacity purposes. The capital spend associated with the program development is requested through the rate case process.

Attachments: *None*

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-8.1a]
Respondent:	J. C. Davis
Page:	1 of 1

Question: Please refer to the documents provided in response to ABDE-2.2 2nd supplemental, which detail the costs associated with the portions of the nuclear decommissioning study that will be conducted by Callan LLC and Energy Solutions LLC, as well as Exhibit A-13 C5.16.

a. Please provide all supporting workpapers that justify the CY 2019 and CY 2020 costs for the nuclear decommissioning study (line 23 on Exhibit A-13 C5.16) in excess of the contracted amounts identified in the Callan LLC and Energy Solutions LLC contracts.

Answer: The proposed Fermi 2 nuclear decommissioning study is intended to be a comprehensive and fully transparent product depicting the most reasonable and accurate view of the decommissioning of the Fermi 2 Power Plant with the understanding that the decommissioning of the Fermi 2 Power Plant is not expected to occur until at least 2045. As described in my response to ABDE-2.1, the scopes of work currently provided by Energy Solutions LLC and Callan LLC are aspects of the broader decommissioning study. It is reasonable and prudent to update other aspects of decommissioning including analysis or validation of regulatory requirements, projected rate of return for the decommissioning trust funds, and study quality. Nuclear Generation provided a detailed forecast in Section 11, Attachment 9 of the Part III submission calculating the constituent parts of the projected Fermi 2 Nuclear Decommissioning Study expenditures depicted on line 23 of Exhibit A-13, Schedule C5.16 inclusive of the projected expenditures for these services.

DTE Electric forecasts awarding the contracted amounts for these other aspects of decommissioning as it is reasonable and prudent to do so, consistent with total projected expenditures for the Fermi 2 nuclear decommissioning Study.

Attachments: None

DTE Electric Company

Demand Response Adjustment 1
Removal of DTE Insight Program Costs
($000)

Line	Description	DTE Proposed[1] (1)	DTE Insight Adjustment[2] (2)	ABATE Adjusted (3)
1	Rate Base	18,251,329	(1,549)	18,249,780
2	Adjusted Net Operating Income	788,214	288	788,503
3	Overall Rate of Return	4.32%	0.00%	4.32%
4	Projected Rate of Return	5.73%	0.00%	5.73%
5	Income Requirements	1,046,495	(9)	1,046,479
6	Income Deficiency (Sufficiency)	258,281	(297)	257,976
7	Revenue Conversion Factor	1.3496	1.3496	1.3496
8	Revenue Deficiency (Sufficiency)	348,584	(401)	348,174
9	Tree Trim Surge Program	2,104	-	2,104
10	**Total Deficiency / (Sufficiency)**	**350,688**	**(401)**	**350,278**

Sources:
[1] DTE Exhibit A-11, Schedule A1.
[2] ABATE Adjustments to DTE Exhibit A-12, Schedule B5.6, at ABATE's recommended ROR. Only excludes DTE Insight.

DTE Electric Company

Demand Response Adjustment 2
Return on Historical and Forecasted DR Programs
($000)

Line	Description	DTE Proposed[1]	All Other DR Programs Historical[2]	All Other DR Programs Forecasted[3]	ABATE Adjusted
		(1)	(2)	(3)	(4)
1	Rate Base	18,251,329	(7,843)	(14,876)	18,228,610
2	ABATE Pre-Tax ROR[4]		6.47%	6.47%	
3	Revenue Deficiency / (Sufficiency)	350,688	(507)	(962)	349,218

Sources:
[1] DTE Exhibit A-11, Schedule A1.
[2] Page 3.
[3] ABATE Adjustments to DTE Exhibit A-12, Schedule B5.6. Does not include DTE Insight.
[4] DTE Exhibit A-14, Schedule D1, at ABATE's recommended 9.2% ROE.

DTE Electric Company

Demand Response Adjustment 2
Historical DR Amortization
($000)

Line	Description	2014 (1)	2015 (2)	2016 (3)	2017 (4)	2018 (5)	2019 (6)	April 2020 (7)	April 2021 (8)	Total (9)
	Gross Plant									
1	Interruptible Air Conditioning (IAC)	-	1,130	7,353	4,304	3,844	7,790	587	2,841	27,849
2	Programmable Communicating Thermostats (PCT)	-	-	-	2,074	4,670	2,969	462	-	10,175
3	Other Demand Response Pilots	-	-	-	-	1,050	2,976	712	4,091	8,829
4	Subtotal Demand Response	-	1,130	7,353	6,378	9,564	13,735	1,761	6,932	46,853
5	DTE Insight	516	4,770	5,349	6,295	581	800	275	1,579	20,165
6	Total Demand Side Management	516	5,900	12,702	12,673	10,145	14,535	2,036	8,511	67,018
7	**2014 to 2019 Total Gross Plant**						**56,471**			
	Amortization (5 Years)									
8	2014	103								
9	2015	103	1,180							
10	2016	103	1,180	2,540						
11	2017	103	1,180	2,540	2,535					
12	2018	103	1,180	2,540	2,535	2,029				
13	2019	-	1,180	2,540	2,535	2,029	2,907			
14	April 2020	-	-	2,540	2,535	2,029	2,907	407		
15	April 2021	-	-	-	2,535	2,029	2,907	407	1,702	
16	Total	516	5,900	12,702	12,673	8,116	8,721	814	1,702	51,145
17	**2014 to 2019 Total Amortization**						**48,628**			
18	**Net Plant Estimate**						**7,843**			

Source:
DTE response ABDE-4.37c.

DTE Electric Company

O&M Inflation Adjustment
($000)

Line	Description	Company Proposed Adjusted 12/31/2018 (1)	Company Proposed 12/31/2019 (2)	Company Proposed 12/31/2020 (3)	Company Proposed Test Year 4/30/2021 (4)	ABATE Proposed[1] Adjusted 12/31/2018 (5)	ABATE Proposed[1] 12/31/2019 (6)	ABATE Proposed[1] 12/31/2020 (7)	ABATE Proposed[1] Test Year 4/30/2021 (8)
	Inflation Rates								
1	Labor	Wage Inflation	3.0%	3.0%	3.0%	Annual CPI-U	2.0%	2.1%	2.3%
2	Materials	Annual CPI-U	2.0%	2.1%	2.3%	Annual CPI-U	2.0%	2.1%	2.3%
3	Outside Services	Wage Inflation	3.0%	3.0%	3.0%	Annual CPI-U	2.0%	2.1%	2.3%
4	Non-Labor	Annual CPI-U	2.0%	2.1%	2.3%	Annual CPI-U	2.0%	2.1%	2.3%
5	Labor Expenses	$ 540,282	$ 540,282	$ 556,490	$ 573,185	$ 540,282	$ 540,282	$ 551,088	$ 562,660
6	Inflation Adjustments		16,208	16,695	5,732		10,806	11,573	4,314
7	Other Adjustments	-	-	-	(5,214)	-	-	-	(5,214)
8	Total Labor Expenses	$ 540,282	$ 556,490	$ 573,185	$ 573,703	$ 540,282	$ 551,088	$ 562,660	$ 561,760
9	Materials Expenses	$ 70,329	$ 70,329	$ 71,736	$ 73,242	$ 70,329	$ 70,329	$ 71,736	$ 73,242
10	Inflation Adjustments		1,407	1,506	562		1,407	1,506	562
11	Other Adjustments	-	-	-	(1,577)	-	-	-	(1,577)
12	Total Materials Expenses	$ 70,329	$ 71,736	$ 73,242	$ 72,227	$ 70,329	$ 71,736	$ 73,242	$ 72,227
13	Outside Services Expenses	$ 372,427	$ 372,427	$ 383,600	$ 395,108	$ 372,427	$ 372,427	$ 379,876	$ 387,853
14	Inflation Adjustments		11,173	11,508	3,951		7,449	7,977	2,974
15	Other Adjustments	-	-	-	(4,783)	-	-	-	(4,783)
16	Total Outside Services Expenses	$ 372,427	$ 383,600	$ 395,108	$ 394,276	$ 372,427	$ 379,876	$ 387,853	$ 386,043
17	Other Non Labor Expenses	$ 85,521	$ 85,521	$ 87,231	$ 89,063	$ 85,521	$ 85,521	$ 87,231	$ 89,063
18	Inflation Adjustments		1,710	1,832	683		1,710	1,832	683
19	Other Adjustments	-	-	-	18,189	-	-	-	18,189
20	Total Other Non Labor Expenses	$ 85,521	$ 87,231	$ 89,063	$ 107,935	$ 85,521	$ 87,231	$ 89,063	$ 107,935
21	**Sub-Total O&M Expense**	**$ 1,068,559**	**$ 1,099,057**	**$ 1,130,598**	**$ 1,148,141**	**$ 1,068,559**	**$ 1,089,930**	**$ 1,112,819**	**$ 1,127,965**
22	Inflation Reconciliation[2]				$ (3,170)				$ (514)
23	Uncollectible Accounts Expense				51,620				51,620
24	Pension and Benefits				156,855				156,855
25	**Total O&M Expense**				**$ 1,353,445**				**$ 1,335,926**
26	**Difference**								**$ (17,519)**

Source and Notes:
Part III Requirements, Supplemental Attachment 6 (Item 5) - O&M Expense, page 3.
[1] The adjustment applies the annual CPI-U inflation rate to labor and outside services. No changes were made to the materials or non-labor inflation rates.
[2] DTE's inflation reconciliation corrects differences between the Part III data and Exhibit A-13 and is described in footnote 3 of Supplemental Attachment 6(5). ABATE's inflation reconciliation was calculated by applying the proposed inflation rates to a copy of DTE Exhibit A-13, Schedule C5.15.

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-3.24c]
Respondent:	A. F. Crozier/Legal
Page:	1 of 1

Question: Referring to Q&A 13 of Adella Crozier's Direct Testimony, please answer the following questions:

c. Describe whether or not DTE Electric is capable of managing O&M escalation to reflect a productivity offset to cost increases, in a way that the expenses will change at a rate slower than the rate of inflation. Please provide copies of all management documents, and efforts to achieve this objective.

Answer: DTE Electric objects to this request for the reasons that the request is vague, overly broad, seeks excessive detail is unduly burdensome and is otherwise not reasonably calculated to lead to the discovery of admissible evidence. Subject to this objection, and without waiving this objection, DTE Electric would answer as follows:

The Company has been able to offset inflation in prior years but has not included any offsets in this case because it is getting harder to find them going forward. We are using our process improvement methodologies to hold costs below the inflation rate. Cost increases above the average inflation rate for base materials and qualified contractor labor are expected to put pressure on our efforts.

Also, see the response to ABDE-3.24a

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-3.24a]
Respondent:	A. F. Crozier/Legal
Page:	1 of 1

Question: Referring to Q&A 13 of Adella Crozier's Direct Testimony, please answer the following questions:

a. Identify any actions taken by DTE Electric to control or minimize non-labor O&M in this case to levels less than the projected rate of general inflation.

Answer: DTE Electric objects to this request for the reasons that the request is vague, overly broad, seeks excessive detail is unduly burdensome and is otherwise not reasonably calculated to lead to the discovery of admissible evidence. Subject to this objection, and without waiving this objection, DTE Electric would answer as follows:

As stated in my testimony at page 8:

> *"DTE Electric has proactively engaged in a number of efforts to improve processes and to reduce costs as much as possible while still providing safe and reliable service to its customers."*

DTE Electric strives to identify and execute sustainable productivity improvements and leverage new technology to help control the Company's cost structure over the long term. With respect to electric generation, the Company has initiatives to minimize capital spending and close the Tier 2 generating plants. The change-over of the generation fleet from coal to other low carbon alternatives will over the long-term result in O&M reductions after 2023. For distribution, the proposed tree trim surge and the modernization of DTE Electric's distribution system equipment are long-term programs to build efficiencies that we expect to realize in a five to ten-year window, depending on the pace of each of those efforts. Witnesses Bruzzano, Morren and Rivard describe these long-term programs in their direct testimony and in supporting exhibits.

MPSC Case No.:	U-20561
Requestor:	Staff
Question No.:	MLE-1.1]
Respondent:	J. L. Morren/T. M. Uzenski/ M. A. Bruzzano/ J. C. Davis/ D. C. Milo/R. A. Bellini/ R. C. Goyanes/D. J. Griffin
Page:	1 of 1

Question: Please answer Yes or No to the following question. Does DTE Electric Company's Projected Capital Expenditures Summary Exhibit A-12, Schedule B5, include reserves or contingency costs?

Answer: Yes.

Fossil Generation includes contingency for Blue Water Energy Center on Line 11 of Exhibit A-12, Schedule B5.1, in the amount of $8,833,000 for 16 months ending 4/30/2020 and $5,733,000 for 12 months ending 4/30/2021.

Corporate Staff includes contingency for the Headquarters Energy Center on Line 5, page 1 of 2 of Exhibit A-12, Schedule B5.8, in the amount of $1,702,000 for 16 months ending 4/30/2020 and $1,477,000 for 12 months ending 4/30/2021.

These are larger, non-routine projects early in their lifecycle which require contingency to mitigate the risk of cost increases due to unforeseen circumstances.

Other than these two exceptions, it is the Company's practice to not include reserves or contingency within the capital projections in the rate case based on previous disallowances.

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Summary - Reserve or Contingency
($000)

Case No.: U-20561
Audit Request: MLE-1.2
Date of Request: 7/22/2019
Respondent: T. M. Uzenski
Page: 1 of 1

Exhibit A-12, Schedule B5

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Capital Expenditures					
		Historical	Projected Bridge Period			Projected Test Year	
Line No.	Description	12 mos. ended 12/31/2018	12 mos. ending 12/31/2019	4 mos. ending 4/30/2020	16 mos. ending 4/30/2020	12 mos. ending 4/30/2021	Reference
					col. (c)+(d)		
1	Production Plant:						
2	Steam	-	-	-	-	-	Exh. A-12, Sch. B5.1
3	Hydraulic	-	-	-	-	-	Exh. A-12, Sch. B5.1
4	Other	-	6,300	2,533	8,833	5,733	Exh. A-12, Sch. B5.1
5	MERC / Fuel Supply	-	-	-	-	-	Exh. A-12,Sch. B5.2
6	Nuclear (including Nuclear Fuel)	-	-	-	-	-	Exh. A-12, Sch.B5.3
7	Distribution	-	-	-	-	-	Exh. A-12, Sch.B5.4
8	Community Lighting	-	-	-	-	-	Exh. A-12, Sch. B5.5
9	Demand Side Management	-	-	-	-	-	Exh. A-12, Sch. B5.6
10	Information Technology	-	-	-	-	-	Exh. A-12, Sch. B5.7
11	Corporate Staff	-	859	843	1,702	1,477	Exh. A-12, Sch. B5.8
12	Charging Forward	-	-	-	-	-	Exh. A-12, Sch. B5.9
13	Total Capital Expenditures	-	7,159	3,376	10,535	7,210	

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Steam, Hydraulic and
Other Power Generation - Reserve or Contingency
($000)

Case No.: U-20561
Audit Request: MLE-1.2
Date of Request: 7/22/2019
Respondent: J. L. Morren
Page: 1 of 9

Exhibit A-12, Schedule B5.1

	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Expenditures				
		Historical	Projected Bridge Period			Projected Test Year
Line No.	Description	12 mos. ended 12/31/2018	12 mos. ending 12/31/2019	4 mos. ending 4/30/2020	16 mos. ending 4/30/2020	12 mos. ending 4/30/2021
					col. (c)+(d)	
1	**Steam Power Generation**					
2	Routine	-	-	-	-	-
3	Non-Routine	-	-	-	-	-
4	Total Steam Power Generation	-	-	-	-	-
5	**Hydraulic Power Generation**					
6	Routine	-	-	-	-	-
7	Non-Routine	-	-	-	-	-
8	Total Hydraulic Power Generation	-	-	-	-	-
9	**Other Power Generation**					
10	Routine	-	-	-	-	-
11	Non-Routine	-	6,300	2,533	8,833	5,733
12	Total Other Power Generation	-	6,300	2,533	8,833	5,733
13	Grand Total	-	6,300	2,533	8,833	5,733

Michigan Public Service Commission
DTE Electric Company
Projected Capital Expenditures
Corporate Staff - Reserve or Contingency
($000)

Case No.: U-20561
Audit Request: MLE-1.2
Date of Request: 7/22/2019
Respondent: T. M. Uzenski
1 of 2

Exhibit A-12, Schedule B5.8

	(a)	(b)	(c)	(d)	(e)	(f)
			Capital Expenditures			
		Historical	**Projected Bridge Period**			**Projected Test Year**
Line No.	**Description**	**12 mos. ended 12/31/2018**	**12 mos. ending 12/31/2019**	**4 mos. ending 4/30/2020**	**16 mos. ending 4/30/2020**	**12 mos. ending 4/30/2021**
					col. (c)+(d)	
1	Vehicle Fleet	-	-	-	-	-
2	Facilities-Construction & Upgrade	-	-	-	-	-
3	Facilities Renovation	-	-	-	-	-
4	Service Center Optimization	-	-	-	-	-
5	Headquarters Energy Center	-	859	843	1,702	1,477
6	Security Measures	-	-	-	-	-
7	NERC-Critical Infrastructure Program	-	-	-	-	-
8	Robotics Process Automation	-	-	-	-	-
9	Customer Service Print Room Upgrade	-	-	-	-	-
10	Other Miscellaneous	-	-	-	-	-
11	Total Corporate Staff	-	859	843	1,702	1,477

Source: Workpaper TMU-1

MPSC Case No.:	U-20561
Requestor:	Staff
Question No.:	JJD-3.1]
Respondent:	J. L. Morren
Page:	1 of 1

Question: Please provide detailed scoping documents for the following projects including: a detailed timeline for all project milestones, expected total and annual project cost, internal budgetary approval status, and contracting strategy including a list of any contractors/suppliers awarded contracts for the project.

Line No.	Description
1	**Steam Power Generation - Non-Routine Additions:**
2	Monroe Dry Fly Ash Basin Slope
3	Monroe Fly Ash Basin Vertical Extension
4	Monroe Dry Fly Ash Dry Conversion (ELG)
6	Belle River Units 1 & 2 DSI
7	316b
10	Sibley Quarry Landfill Modification (CCR)
13	Monroe Bottom Ash Basin Closure (CCR)
14	River Rouge Bottom Ash Basin Closure (CCR)
15	St. Clair Scrubber Basin Closure (CCR)

Answer: For project costs and contract details, please see attachment U-20561 JJD-3.1-01 Non-Routine Project Costs and Matrix.

For project timelines, please see the project documents referred to in the matrix.

All projects are budgeted for in the Company's capital plan. Specific approval statuses can be found in the project documents attached.

For the Line No. 7 project in the question (316b), the Company originally intended to capitalize the studies as part of assets needed to meet the 316b requirements. Since the studies have not led to the construction of new assets, the Company has determined the study costs should be recorded as O&M instead of capital. The Company reclassified actual 316b study expenses to O&M in September 2019.

Attachments: U-20561 JJD-3.1-01 Non-Routine Project Costs and Matrix
U-20561 JJD-3.1-02 PMP 12191
U-20561 JJD-3.1-03 PMP 14080
U-20561 JJD-3.1-04 PMP 11156 Charter
U-20561 JJD-3.1-05 PMP 11156 Revised Charter
U-20561 JJD-3.1-06 MPP Fly Ash Basin Appropriation
U-20561 JJD-3.1-07 Monroe Dry Fly Ash Conversion (ELG) Approval Timeline
U-20561 JJD-3.1-09 PMP 11511
U-20561 JJD-3.1-10 Monroe Dry Ash Conversion Charter
U-20561 JJD-3.1-11 CGB Approved ELG Package
U-20561 JJD-3.1-12 MATS CARF
U-20561 JJD-3.1-13 MATS Charter Rev0
U-20561 JJD-3.1-14 MATS Charter Rev2
U-20561 JJD-3.1-15 BLRPP Study Approved Charter
U-20561 JJD-3.1-16 DCS and Simulator Upgrade
U-20561 JJD-3.1-17 PMP 11231
U-20561 JJD-3.1-18 PMP 11234
U-20561 JJD-3.1-19 PMP 14888
U-20561 JJD-3.1-20 PMP 11449
U-20561 JJD-3.1-21 PMP 11714
U-20561 JJD-3.1-22 PMP 11530
U-20561 JJD-3.1-23 Monroe Bottom Ash Basin Closure (CCR) Timeline
U-20561 JJD-3.1-24 PMP 11509
U-20561 JJD-3.1-25 PMP 14165
U-20561 JJD-3.1-26 PMP 14809
U-20561 JJD-3.1-27 PMP 15146
U-20561 JJD-3.1-28 MPP - Coal Combustion Residual Charter
U-20561 JJD-3.1-29 PMP 13625
U-20561 JJD-3.1-30 PMP 15225
U-20561 JJD-3.1-31 PMP 11430

The documents listed below are available on DTE Electric's Confidential Discovery Portal, an invitation to which has been sent by email to individuals who have properly executed a non-disclosure agreement pursuant to the protective order issued in this case.

U-20561 JJD-3.1-08 Monroe Dry Fly Ash Conversion (ELG) OE Proposal NDA

DTE Energy
Detroit Edison

FOSSIL GENERATION PAT REVIEW REQUEST FORM

PAT-AT Agenda Date:	Forecast	PMP Project ID:	11511
PAT LVL/REV:	Forecast		

[ ] Scope Change	X New Revision
[ ] Cancel	
[ ] Schedule Change	[ ] Release of Risk Funds

Project Site:	MONPP	Project Start Date:	1/2/2019
Unit:	Common	Scope Baseline Date:	NR
Outage Related?	Yes	Constr. Start Date:	7/6/2020
Current IRR:	NR	Project I/S Date:	12/3/2023
SAP Profit Center #:	0202R052	Investment Reason:	9 Enviornmental
WBS Element:	I-000022-		
Project Type/Systems:	14 Common		
Reconciliation Category:	Engineering & Long Lead for Future Projects		

Project Title: Monroe Dry Fly Ash Conversion (ELG)

PMP Problem Description & Project Objective *(Project deliverables? Sum benefits-attach extra sheets if required):*

PROBLEM: Monroe Units 1-4 are not capable of collecting all production fly ash in the dry form. EPA's Effluent Limitation Guidelines (ELG) mandate that under Zero Liquid Discharge (ZLD), transport water for moving flyash must cease by December 31, 2023.

OBJECTIVE: Monroe Units 1-4 would be capable of collecting all production fly ash in the dry form by December 2023.

Brief Project Scope Summary *(Summarize products & services provided)*

Construct an independent Dry Fly Ash Collection system for Monroe Units 1-4.

Reason for Submittal *(State reason for submittal, categorize requested dollar amount changes, and explain any estimate at completion (EAC) benefits or IRR changes):*

This is a pre-PAT-0 request.

SAP Budget Approval	Prior Years	2019	2020	2021
Previously Approved PAT:	$0	$0	$0	$0
PAT Change Request:	$0	$0	$0	$0
Current PAT Request:	$0	$0	$0	$0
Total PAT Request:	$0		Total PAT Change:	$0

Forecast Charge Categories	Current Approved PAT Form				Forecast Changes				Revised PAT Forecast				
	2019	2020	2021	Future Years	2019	2020	2021	Future Years	2019	2020	2021	Future Years	Project Total (EAC)
DTE Labor (Direct)	$0	$0	$0	$0	$250,000	$500,000	$750,000	$2,500,000	$250,000	$500,000	$750,000	$2,500,000	$4,000,000
Contract Labor (Direct)	$0	$0	$0	$0	$3,537,000	$8,500,000	$49,650,000	$41,963,000	$3,537,000	$8,500,000	$49,650,000	$41,963,000	$103,650,000
Material (Direct)	$0	$0	$0	$0	$0	$11,000,000	$7,000,000	$0	$0	$11,000,000	$7,000,000	$0	$18,000,000
Other (Direct)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Shared Costs	$0	$0	$0	$0	$0	$0	$500,000	$2,000,000	$0	$0	$500,000	$2,000,000	$2,500,000
Indirects	$0	$0	$0	$0	$350,000	$2,000,000	$2,500,000	$3,000,000	$350,000	$2,000,000	$2,500,000	$3,000,000	$7,850,000
Sub-Total	$0	$0	$0	$0	$4,137,000	$22,000,000	$60,400,000	$49,463,000	$4,137,000	$22,000,000	$60,400,000	$49,463,000	$136,000,000
Calculated Risk	$0	$0	$0	$0	$0	$0	$0	$13,000,000	$0	$0	$0	$13,000,000	$13,000,000
TOTAL	$0	$0	$0	$0	$4,137,000	$22,000,000	$60,400,000	$62,463,000	$4,137,000	$22,000,000	$60,400,000	$62,463,000	$149,000,000
							Change in Total EAC:	$149,000,000					

Project Developer:	Rick Luberacki	APPROVAL DISPOSITION:	
Project Engineer:	Gary Whitehouse	Without Calculated Risk:	[ ]
Project Manager:	Scott Sobas	With Calculated Risk:	[ ]

Approved by: | Date:

Fos Gen Large Capital Projects Charter

PMP #11511 **Date: April 30, 2019**

Project Name: Monroe Dry Fly Ash Conversion (ELG)

Investment Planning Rep.: Rick Luberacki

Problem Statement

EPA's Effluent Limitation Guidelines (ELG) requirements mandate that under Zero Liquid Discharge (ZLD) transport water for moving fly ash must cease by December 31, 2023.

Current State

Monroe Units 1-4 all utilize a wet extraction and slurry transport system to move precipitator fly ash to the Fly Ash Impoundment Basin for disposal. Units 1 & 2 have equipment capable of handling production fly ash some of the time in the dry form, but is incapable of processing 100% of the fly ash produced by those units, thus requiring some of it to be slurried to the Fly Ash Impoundment. Units 3 & 4 do not have the capability of extracting/collecting any fly ash in the dry form.

Ideal State

Monroe Units 1-4 would be capable of effectively and reliably collecting all production fly ash in the dry form and transporting it to temporary storage silos by the compliance date of December 2023.

Case for Change

Monroe Units 1-4 must comply with ELG requirements for ZLD by December 31, 2023.

Gap to be Corrected

Monroe Units 1-4 are not currently capable for collecting 100% of production fly ash in the dry form.

Summary of Scope

Construct an independent Dry Fly Ash Collection system for Units 1-4.

Expected Benefits	Current State	Target State
Compliance with ELG regulations	Units 1-4 depend on transport water for moving fly ash from the precipitator hoppers to the Fly Ash Impoundment.	Units 1-4 would be capable of collecting 100% of production fly ash all in the dry form, and temporarily storing it.

Schedule Assumptions
Board approval to proceed expected by December 2019
Construction is assumed to start mid-2020
Unit 1 to be converted to 100% dry fly ash collection in December 2022, Unit 4 & U2 by mid-2023, and Unit 3 in December 2023.

Total Estimated Project Cost: $149M

IRR not required - Environmental

Key Business Assumptions

Monroe has been identified as a long-term asset in the fossil generation fleet.

Challenges/Risks to Successful Completion

Equipment supplier is able to meet required delivery dates.

Fos Gen Large Capital Projects Charter

Approver	Initial	Date
Plant Manager: Mike Twomley		
Project Sponsor: Jim Good		
Plant Financial Controller: Shannon Bell		
Primary SME:		
SME Manager:		
Plant EM&R: Lisa Lockwood		

PMP #11511 **Date: April 30, 2019**

Project Name: Monroe Dry Fly Ash Conversion (ELG)

Investment Planning Rep.: Rick Luberacki

Included in Scope

1. Engineer, procure and construct a complete and independent dry fly ash collection system for Units 1-4.

Excluded from Scope

Acceptance Criteria

Fos Gen Large Capital Projects Charter

PMP # 14809 **Date: 02/25/2019**

Project Name: MONPP Area 15 Closure by Removal (Study)

Investment Planning Rep.: S. Patel

Problem Statement

The Area 15 Coal Combustion Residuals (CCR) impoundment was commissioned in 1971, when U1 was brought online. The purpose of the impoundment was to treat various wastewaters and store Bottom Ash (BA) material discharge from the plant, which was conveyed via pipeline. In order to support the Company's CCR compliance program, the Area 15 CCR Impoundment was declared inactive in October 15, 2015 following the commissioning of the BA dewatering tank system. The CCR rule "inactive" status was later reversed by further EPA rulemaking, however, due to not meeting certain location restrictions, the Area 15 CCR impoundment is subject to forced closure by October 31, 2020. Closure must be completed within 5 years with extensions available under certain circumstances.

The volume of CCR material and depth of ground contamination is not currently known. In addition, logistics requirements have not been determined, and whether the current on-site road and bridge infrastructure can sustain.

Current State

Based on recommendations by Fossil Generation and EM&R, the Risk Management Committee (RMC) made the decision to pursue closure by removal, with trucking being the choice of transportation, and disposal of CCR material at Sibley Quarry.

Ideal State

Evaluation of Area 15 will provide an understanding of volume of CCR material currently present within Area 15. Based on that, the logistics requirements and impact on infrastructure can be determined, along with identification of necessary reinforcement or repairs that may need to be performed.

Project Benefits

Expected Benefits	Current State	Target State
Approximate volume of CCR material and/or contaminated ground quantified	The volume of CCR material within Area 15 is not currently known.	Known estimate of material within Area 15 impoundment.
Identify current condition and necessary repairs of roads and bridge infrastructure	Current condition and sustainability of on-site infrastructure is not known.	Obtain recommendation for reinforcement and repair.
Determine logistics requirements for trucking CCR material to Sibley Quarry	Trucking requirements of CCR material has not been determined.	Determine logistics requirements based on material to be moved.

Key Business Assumptions

Environmental compliance must be maintained for the continued operation of MONPP. Monroe units are classified as tier-1 assets in the Fossil Generation fleet.

Case for Change

Evaluation of the Area 15 CCR impoundment is required in order to achieve closure by removal.

Gap to be Corrected

1. Geology and volume of CCR material within Area 15 that needs to be removed in order to comply with CCR rule is currently unknown.
2. Logistical requirements to remove CCR material need to be determined based on geological survey of Area 15.
3. Condition of roads and bridges along proposed truck route surrounding MONPP to move CCR material from Area 15 is unknown.

Summary of Scope

- Perform Standard Penetration Test (SPT) boring, Cone Penetration Test (CPT) sounding, and waste characterization analysis within Area 15.
- Evaluate logistical requirements to perform closure by removal based on Area 15 material analysis.
- Inspect condition of roads and bridges, and generate recommendation for repair or reinforcement.
- Determine Rough Order of Magnitude (ROM) project cost to perform closure by removal for Area 15.

Schedule Assumptions
3-week lead time for transportation and mobilization of amphibious rig.
Area 15 drilling and sampling is expected to take 26 days once equipment is mobilized.
Traffic and infrastructure analysis is expected to be completed within 60 days following issuance of PO.

Total Estimated Project Cost: $800,000

IRR = N/A (Environmental)

Challenges/Risks to Successful Completion

Timeline to seek full Board of Directors (BOD) approval for this project is targeted for September 2019. This allows for approximately 1-year to develop a design and execution strategy. Schedule compression may be required following BOD approval.

Fos Gen Large Capital Projects Charter

PMP # 14809 **Date: 02/25/2019**

Project Name: MONPP Area 15 Closure by Removal (Study)

Investment Planning Rep.: S. Patel

Included in Scope

Summarization of Study:

I. Geotechnical subsurface exploration of Area 15 to verify underlying geologic formation, quantify material to be removed, make geotechnical recommendations to facilitate closure by removal, and perform waste characterization/geotechnical analysis for disposal.
II. Evaluate logistics requirements for closure by removal of Area 15 via trucking, and assess impact to roads and infrastructure along route.
III. Refine Rough Order of Magnitude cost estimate based on collected data mentioned in items I. and II.

Bottom Ash Geotechnical Evaluation:

1. DTE project oversight is included for this project.
2. Vendor to utilize amphibious drilling rig to perform the following field activities:
   a) Forty-Three (43) CPT sounding locations on an approximate 250ft x 250ft grid across Area 15. Soundings will advance from the mudline to the bottom of CCR.
   b) Fifteen (15) SPT boring and CPT sounding locations. Each of these shall include a standard geotechnical boring with SPT sampling. Vertical sample interval is 5ft.
   c) Four (4) representative samples from the Area 15 basin (2 on land, and 2 from the open water). Evaluate for Resource Conservation & Recovery Act (RCRA) 8 metals by Toxic Characteristic Leaching Procedure (TCLP).
3. Laboratory testing will include the following but is not limited to:
   a) Moisture Content
   b) Grain Size Analysis
   c) Atterberg Limits
   d) 3-Point Unconsolidated Undrained Triaxial Test (minimum of 6)
   e) 3-Point Consolidated Undrained Triaxial Test (minimum of 3)
   f) One Dimensional Consolidation
   g) Laboratory Permeability Test
   h) Standard Proctor Compaction Test
   i) Organic Content Test
   j) Specific Gravity Test
   k) Other Tests as identified by EM&R
4. Evaluate quantity and means of CCR material that needs to be dewatered during the removal process prior to being transported for disposal.
5. Vendor to submit geotechnical Data Report to DTE point of contact for distribution.

Traffic & Infrastructure Evaluation:

1. Determination of total quantity of material to be handled from data obtained through geotechnical analysis of Area 15.
2. Collect traffic information along route and conduct performance evaluation to include a minimum of the following:
   a) Overall timeline to transport the material from MONPP to Sibley Quarry.
   b) Evaluation of nominal traffic conditions (capacity, security check-in, admin processing, etc).
   c) Capacity handling facilities at both ends.
3. Compliance check with applicable laws to include load restrictions, timing of operation of heavy vehicles, climate bylaws, any other safety concerns with carrying such materials on public roads.
4. Perform road/pavement condition assessment within plant site and Front St.
5. Perform inspection and analysis for the MONPP E. Front St. entrance bridge to include the following:
   a) Visual bridge structural assessment and load capacity analysis.
   b) Underwater visual assessment of the abutments and piers.
6. Determine the potential need for repair, reinforcement or replacement of any existing roads, bridges before project start and/or after completion.
7. Evaluate material handling needs including queue areas, security/process check-in areas, loading/unloading site.
8. Provide recommendation for the following:
   a) Vehicle sizing based on material to be transported and logistical and regulatory constraints.
   b) Volume of vehicles required to transport all CCR material identified for removal in the geotechnical evaluation.
   c) Repair and/or reinforcement of entrance bridge and load capacity rating.
   d) Repair and/or reinforcement of roads on-site and along Front St.
   e) Location for material handling in the form of a rough sketch.
9. Vendor(s) to submit traffic and infrastructural reports to DTE point of contact for distribution.

ROM Cost Estimate:

1. Vendor to provide a Rough Order of Magnitude cost estimate for closure by removal of Area 15 based on data obtained during this study.

Fos Gen Large Capital Projects Charter

PMP # 14809 **Date: 02/25/2019**

Project Name: MONPP Area 15 Closure by Removal (Study)

Investment Planning Rep.: S. Patel

Approver	Initial	Date
ESO Director: I. Deol	ID /s/	2/25/2019
Plant Manager: M. Twomley	MT /s/	2/25/2019
Plant Sponsor: J. Good	JG /s/	2/25/2019
Plant Financial Controller: S. Bell	SB /s/	2/25/2019
Civil SME: N. Reidenbach	NR /s/	2/25/2019
EM&R Manager: Rob Lee	N/A	N/A

Included in Scope Cont'd

Beneficial Use Analysis for Area 15:

1. Vendor to utilize amphibious drilling rig to perform Seven (7) CPT sounding locations as specified by vendor. Soundings will advance from the mudline to the bottom of CCR.
2. Vendor to develop 3D conceptual site visualization model to survey and characterize the material within the Area 15 impoundment.

Excluded from Scope

1. Detailed engineering, procurement and construction for closure by removal of Area 15. This work will require an amendment to the charter or decision document to be approved as well as Board of Directors approval for the project.
2. Investigation or review pertaining to the MONPP Flyash Basin.
3. Engineering or construction pertaining to the process waste water (chem ditch) project. This is to be addressed under a separate project.

Acceptance Criteria

1. Determination of quantity of CCR material that will need to be removed from Area 15.
2. Geotechnical and chemical characteristics of CCR material within Area 15.
3. Understanding of logistics requirements to facilitate closure by removal via means of trucking from MONPP to Sibley Quarry.
4. Understanding of necessary infrastructure repairs or reinforcement required before and/or after start of project.

I-000022-0342

DTE Energy
Detroit Edison

FOSSIL GENERATION PAT REVIEW REQUEST FORM

PAT-AT Agenda Date:			
PMP Project ID:	14809		
PAT LVL/REV:	PAT 0 REV 0		
Project Site:	MONPP	Project Start Date:	3/4/2019
Unit:	Common	Scope Baseline Date:	NR
Outage Related?	No	Constr. Start Date:	3/4/2019
Current IRR:	NR	Project I/S Date:	10/31/2019
SAP Profit Center #:	0202R165	Investment Reason:	9 Enviornmental
WBS Element:			
Project Type/Systems:	08 Plant Waste		
Reconciliation Category:	Emergent Work Allocation		

☐ Scope Change ☒ New Revision ☐ Cancel
☐ Schedule Change ☐ Release of Contingency

Project Title: MONPP Area 15 Boring & Infrastructure Study

PMP Problem Description & Project Objective *(Project deliverables? Sum benefits-attach extra sheets if required):*

PROBLEM: The volume of CCR material and depth of ground contamination is not currently known. In addition, logistics requirements have not been determined, and whether the current on-site road and bridge infrastructure can sustain.

OBJECTIVE: Evaluation of Area 15 will provide an understanding of volume of CCR material currently present within Area 15. Based on that, the logistics requirements and impact on infrastructure can be determined, along with identification of necessary reinforcement or repairs that may need to be performed.

Brief Project Scope Summary *(Summarize products & services provided)*

1. Mobilize drilling equipment.
2. Perform ground boring and depth analysis on Area 15.
3. Perform site entrance bridge structural evaluation.
4. Perform traffic study and logistics evaluation for removing and transporting CCR material from Area 15 to Sibley Quarry.
5. Develop 3D conceptual site visualization model.

Reason for Submittal *(State reason for submittal, categorize requested dollar amount changes, and explain any estimate at completion (EAC) benefits or IRR changes):*

This is a PAT-0 request to perform a geotechnical evaluation of Area 15, site entrance bridge structural evaluation and traffic study.

SAP Budget Approval	Prior Years	2019	2020	Future Years
Previously Approved PAT:	$0	$0	$0	$0
PAT Change Request:	$0	$724,593	$0	$0
Current PAT Request:	$0	$724,593	$0	$0
Total PAT Request:	$724,593	Total PAT Change:		$724,593

Forecast Charge Categories	Current Approved PAT Form				Forecast Changes				Revised PAT Forecast				
	Prior Years	2019	2020	Future Years	Prior Years	2019	2020	Future Years	Prior Years	2019	2020	Future Years	Project Total (EAC)
DTE Labor (Direct)	$0	$0	$0	$0	$0	$34,605	$0	$0	$0	$34,605	$0	$0	$34,605
Contract Labor (Direct)	$0	$0	$0	$0	$0	$607,211	$0	$0	$0	$607,211	$0	$0	$607,211
Material (Direct)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other (Direct)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Shared Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Indirects	$0	$0	$0	$0	$0	$82,777	$0	$0	$0	$82,777	$0	$0	$82,777
Sub-Total	$0	$0	$0	$0	$0	$724,593	$0	$0	$0	$724,593	$0	$0	$724,593
Contingency	$0	$0	$0	$0	$0	$75,407	$0	$0	$0	$75,407	$0	$0	$75,407
TOTAL	$0	$0	$0	$0	$0	$800,000	$0	$0	$0	$800,000	$0	$0	$800,000

Change In Total EAC: $800,000

Project Developer:	Sulove Patel	APPROVAL DISPOSITION:	
Project Engineer:	Bob Warner	Without Contingency:	☐
Project Manager:	Reza Rajabian	With Contingency:	☒

Approved by: [signature] Date: 3/25/2019

See SWI (Standard Work Instruction) ALLPP-SWI-03-004-011-0643 for instructions on filling out this form

Form: ALLPP-FM-0013 Rev: 6 Date: 11/2/16

PMP # 14165 Date: 07/05/18

Fos Gen Large Capital Projects Charter

Project Name: Monroe Area 15 (Bottom Ash Basin) – Groundwater Contamination Mitigation Project

Investment Planning Rep.: Harry Mueller

Problem Statement

Monroe Power Plant Area 15 (Bottom Ash Basin), which is an inactive Coal Combustion Residuals (CCR) surface impoundment, needs to have mitigation plans in place in the event it is determined that a release from the CCR unit to groundwater has occurred.

Current State

Area 15 (Bottom Ash Basin) at the Monroe Power Plant is approximately 100 acre inactive CCR impoundment as defined by 40 CFR §257.53.

A groundwater monitoring system was installed in 2016 and 2017 to allow sampling of the groundwater around the perimeter of Area 15 (Bottom Ash Basin).

In the future, if groundwater sampling results indicate that a release from the CCR unit has occurred, DTE needs to have a plan in place that can be implemented to mitigate further releases.

Ideal State

There is no release from the CCR unit to groundwater.

Project Benefits		
Expected Benefits	**Current State**	**Target State**
A plan will be in place to address any release of CCRs into the groundwater around the Monroe Area 15 (Bottom Ash Basin).	There is no mitigation plan in the event groundwater samples from Area 15 indicate a release from the CCR unit to groundwater has occurred.	There is no contamination released from the Monroe Area 15 (Bottom Ash Basin).

Key Business Assumptions

- The Monroe Area 15 (Bottom Ash Basin) is an inactive CCR surface impoundment and does not change status.

Case for Change

- The Monroe Area 15 (Bottom Ash Basin) is an inactive CCR surface impoundment which is being monitored to verify the integrity to prevent contamination from being release into the environment. In the even a release does occur, a mitigation plan needs to be in place to mitigate the release.

Gap to be Corrected

- A mitigation plan needs to be in place in the event a release from the CCR unit to groundwater is discovered.

Summary of Scope

This project evaluates options and develops a plan for risk mitigation in the event CCRs are released to the groundwater around the Monroe Power Plant Area 15 (Bottom Ash Basin).

Schedule Assumptions
Outage month and duration that construction will take place: TBD
Material procurement time: TBD
Engineering time: TBD
Additional key dates: None identified

Total Estimated Project Cost: $244K	Payback = N/A	Prelim IRR = Environmental

Challenges/Risks to Successful Completion

- If there is a release of CCR from Area 15 (Bottom Ash Basin) to the groundwater, there is sufficient time given to design and implement the solution to remediate the release.

Fos Gen Large Capital Projects Charter

PMP # 14165 Date: 07/05/18

Project Name: Monroe Area 15 – Groundwater Contamination Mitigation Project

Investment Planning Rep.: Harry Mueller

Approver	Initial	Date
Plant Manager: Michael Twomley		
Project Sponsor: Robert Lee		
Plant Financial Controller: Kyle Kantola		
Primary SME: Robert Lee		
SME Manager: Robert Lee		
Plant EM&R: Lisa Lockwood		

Included in Scope

1. This project develops and evaluates options to mitigate a release of CCR material to groundwater in the event this occurs in the future.
2. A mitigation plan will be developed up to and including conceptual design and engineering cost estimate.
3. Review existing site information including groundwater data, hydrogeologic reports, and available information on DTE's CCR external website.
4. Develop a tabular and visual presentation of groundwater data that shows the quality of groundwater around the perimeter of the bottom ash basin.
5. Provide a list and description of viable technologies that could be employed to capture, control, or eliminate the movement of groundwater potentially affected by CCR constituents of concern around the bottom ash basin. Include the following in addition to other viable technologies that are identified:
   a) Removal of the CCR material from Area 15.
   b) Installation of a perimeter slurry wall around Area 15.
   c) Techniques to control and capture groundwater.
6. Develop a conceptual design and engineering cost estimate (+/- 30%) for each viable technology or methodology. As part of conceptual design efforts, consider groundwater and hydrogeological data as appropriate to each technology/method evaluated.
7. Prepare an assessment/comparison of the viable technologies identified based on anticipated effectiveness, implementation ability, sustainability, and capital and operational cost. Based on these criteria, summarize advantages and disadvantages for each technology.
8. Proposed project schedule:
   a) July 20·2018 – DTE to issue purchase order
   b) July 31, 20108 – Kick off meeting completed and any additional reports / material provided
   c) August 31, 2018 – Draft feasibility report submitted electronically to DTE
   d) September 7, 2018 DTE comments
   e) September 15, 2018 – Final report submitted

Excluded from Scope

1. This project does not investigate or review anything pertaining to the Coal Pile Runoff Pond.
2. This project does not investigate or review anything pertaining to the Monroe Power Plant Flyash Basin.
3. This project does not investigate or review anything pertaining to the Monroe Power Plant Vertical Extension Landfill.

Acceptance Criteria

1. A CCR unit release to groundwater mitigation plan is developed.
2. Conceptual design and engineering is completed with +/- 30% cost estimate for each option evaluated.

I-000022-0317

DTE Energy
Detroit Edison

FOSSIL GENERATION PAT REVIEW REQUEST FORM

PAT-AT Agenda Date:	7/19/2018
PMP Project ID:	14165
PAT LVL/REV:	PAT 0 REV 0
Project Site: MONPP	Project Start Date: 7/30/2018
Unit: Common	Scope Baseline Date:
Outage Related? No	Constr. Start Date: 9/1/2018
Current IRR: N/A	Project I/S Date: 12/31/2018
SAP Profit Center #: 0202R165	Investment Reason: 9 Environmental
WBS Element:	I-000022
Project Type/Systems:	06 Grounds & Physical Plant
Reconciliation Category:	Emergent Work Allocation

☐ Scope Change   [x] New Revision   ☐ Cancel
☐ Schedule Change   ☐ Release of Contingency

Project Title: Monroe Area 15 (Bottom Ash Basin) - Groundwater Contamination Mitigation Project

PMP Problem Description & Project Objective *(Project deliverables? Sum benefits-attach extra sheets if required):*

Problem Description: Monroe Power Plant Area 15 (Bottom Ash Basin), which is an inactive Coal Combustion Residuals (CCR) surface impoundment, needs to have mitigation plans in place in the event it is determined that a release from the CCR unit to groundwater has occurred.

Project Objective: A mitigation plan is in place in the event a release from Monroe Power Plant Area 15 (Bottom Ash Basin) occurs contaminating the groundwater around Area 15.

Brief Project Scope Summary *(Summarize products & services provided)*

This project evaluates options and develops a plan for risk mitigation in the event CCRs are released to the groundwater around the Monroe Power Plant Area 15 (Bottom Ash Basin).

Reason for Submittal *(State reason for submittal, categorize requested dollar amount changes, and explain any estimate at completion (EAC) benefits or IRR changes):*

This is a PAT0 request to fund project initiation and begin conceptual engineering work.

SAP Budget Approval	Prior Years	2018	2019	2020
Previously Approved PAT:	$0	$0	$0	$0
PAT Change Request:	$0	$203,700	$0	$0
Current PAT Request:	$0	$203,700	$0	$0
Total PAT Request:	$203,700		Total PAT Change:	$203,700

Forecast Charge Categories	Current Approved PAT Form: Prior Years	2018	2019	Future Years	Forecast Changes: Prior Years	2018	2019	Future Years	Revised PAT Forecast: Prior Years	2018	2019	Future Years	Project Total (EAC)
DTE Labor (Direct)	$0	$0	$0	$0	$0	$46,150	$0	$0	$0	$46,150	$0	$0	$46,150
Contract Labor (Direct)	$0	$0	$0	$0	$0	$100,000	$0	$0	$0	$100,000	$0	$0	$100,000
Material (Direct)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other (Direct)	$0	$0	$0	$0	$0	$500	$0	$0	$0	$500	$0	$0	$500
Shared Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Indirects	$0	$0	$0	$0	$0	$57,050	$0	$0	$0	$57,050	$0	$0	$57,050
Sub-Total	$0	$0	$0	$0	$0	$203,700	$0	$0	$0	$203,700	$0	$0	$203,700
Calculated Risk	$0	$0	$0	$0	$0	$40,000	$0	$0	$0	$40,000	$0	$0	$40,000
TOTAL	$0	$0	$0	$0	$0	$243,700	$0	$0	$0	$243,700	$0	$0	$243,700

Change In Total EAC: $243,700

Project Developer:	H. Mueller	APPROVAL DISPOSITION:
Project Engineer:	~~TBD~~ R. WARNER	Without Calculated Risk: ☐
Project Manager:	~~TBD~~ R. RAJABIAN	With Calculated Risk: [X]

Approved by: [signature]   Date: 7/18/2018

See SWI (Standard Work Instruction) ALLPP-SWI-03-004-011-0643 for instructions on filling out this form

Form: ALLPP-FM-0013 Rev: 6 Date: 11/2/16

DTE Energy
Detroit Edison

FOSSIL GENERATION PAT REVIEW REQUEST FORM

PAT-AT Agenda Date:	Forecast
PMP Project ID:	15146
PAT LVL/REV:	PAT 0 Rev 0
Project Site:	MONPP
Unit:	Common
Outage Related?	No
Current IRR:	NA
SAP Profit Center #:	0202R165
WBS Element:	
Project Type/Systems:	02 Bolier/Steam Generator
Reconciliation Category:	Approved Projects in Development
Project Complexity:	Medium
Project Start Date:	Forecast
Constr. Start Date:	Forecast
Project I/S Date:	Forecast
Investment Reason:	9 Environmental

☐ Scope Change ☒ New Revision ☐ Cancel
☐ Schedule Change ☐ Realized Risk

Project Title: Monroe Bottom Ash Basin Closure (CCR)

PMP Problem Description & Project Objective *(Project deliverables? Sum benefits-attach extra sheets if required):*

PROBLEM: The Monroe Bottom Ash Basin (Area 15) Coal Combustion Residuals (CCR) impoundment was commissioned in 1971, when U1 was brought online. The purpose of the impoundment was to treat various wastewaters and store Bottom Ash (BA) material discharge from the plant, which was conveyed via pipeline. In order to support the Company's CCR compliance program, the Area 15 CCR Impoundment was declared inactive in October 15, 2015 following the commissioning of the BA dewatering tank system. The CCR rule "inactive" status was later reversed by further EPA rulemaking, however, due to not meeting certain location restrictions, the Area 15 CCR impoundment is subject to forced closure by October 31, 2020. Closure must be completed within 5 years with extensions available under certain circumstances.
OBJECTIVE: The Monroe Bottom Ash Basin is clean closed by removal of CCR material no later than October 31, 2025.

Brief Project Scope Summary *(Summarize products & services provided)*

1. Perform geotechnical analysis and engineering for closure by removal.
2. Excavate and dredge CCR material.
3. Test and certify that the basin is clear of CCR material.

Reason for Submittal *(State reason for submittal, categorize requested dollar amount changes, and explain any estimate at completion (EAC) benefits or IRR changes):*

This is a PAT-0 request for project initiation.

SAP Budget Approval	Prior Years	2019	2020	Future Years
Previously Approved PAT:	$0	$0	$0	$0
PAT Change Request:	$0	$0	$0	$0
Current PAT Request:	$0	$0	$0	$0
Total PAT Request:	$0		Total PAT Change:	$0

Forecast Charge Categories	Current Approved PAT Form				Forecast Changes				Revised PAT Forecast				
	Prior Years	2019	2020	Future Years	Prior Years	2019	2020	Future Years	Prior Years	2019	2020	Future Years	Project Total (EAC)
DTE Labor (Direct)	$0	$0	$0	$0	$0	$375,000	$300,000	$4,200,000	$0	$375,000	$300,000	$4,200,000	$4,875,000
Contract Labor (Direct)	$0	$0	$0	$0	$0	$1,400,000	$3,000,000	$55,000,000	$0	$1,400,000	$3,000,000	$55,000,000	$59,400,000
Material (Direct)	$0	$0	$0	$0	$0	$0	$250,000	$2,500,000	$0	$0	$250,000	$2,500,000	$2,750,000
Other (Direct)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Shared Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Indirects	$0	$0	$0	$0	$0	$225,000	$450,000	$12,300,000	$0	$225,000	$450,000	$12,300,000	$12,975,000
Sub-Total	$0	$0	$0	$0	$0	$2,000,000	$4,000,000	$74,000,000	$0	$2,000,000	$4,000,000	$74,000,000	$80,000,000
Calculated Risk	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL	$0	$0	$0	$0	$0	$2,000,000	$4,000,000	$74,000,000	$0	$2,000,000	$4,000,000	$74,000,000	$80,000,000
							Change in Total EAC:	$80,000,000					

Project Developer:	Sulove Patel	APPROVAL DISPOSITION:	
Project Engineer:	Saeid Labaf	Without Risk:	
Project Manager:	Bill Casey	With Risk:	Approved by: Date:

See SWI (Standard Work Instruction) ALLPP-SWI-03-004-011-0643 for instructions on filling out this form

Fos Gen Large Capital Projects Charter

PMP # 15146 **Date: Forecast**

Project Name: Monroe Bottom Ash Basin Closure (CCR)

Investment Planning Rep.: S. Patel

Problem Statement

The Monroe Bottom Ash Basin (Area 15) Coal Combustion Residuals (CCR) impoundment was commissioned in 1971, when U1 was brought online. The purpose of the impoundment was to treat various wastewaters and store Bottom Ash (BA) material discharge from the plant, which was conveyed via pipeline. In order to support the Company's CCR compliance program, the Area 15 CCR Impoundment was declared inactive in October 15, 2015 following the commissioning of the BA dewatering tank system. The CCR rule "inactive" status was later reversed by further EPA rulemaking, however, due to not meeting certain location restrictions, the Area 15 CCR impoundment is subject to forced closure by October 31, 2020. Closure must be completed within 5 years with extensions available under certain circumstances.

Current State

Based on recommendations by Fossil Generation and EM&R, the Risk Management Committee (RMC) made the decision to pursue closure by removal, with trucking being the choice of transportation, and disposal of CCR material at Sibley Quarry.

Ideal State

A closure by removal solution can be identified and executed with a target completion of October 31, 2025.

Project Benefits		
Expected Benefits	**Current State**	**Target State**
Perform closure of the Bottom Ash Basin CCR Impoundment	Not Closed	Monroe Bottom Ash Basin is classified as closed

Key Business Assumptions

Environmental compliance must be maintained for the continued operation of MONPP. Monroe units are classified as tier-1 assets in the Fossil Generation fleet.

Case for Change

Perform closure by removal of CCR material within Area 15 to comply with CCR rules set forth by the EPA.

Gap to be Corrected

1. The Monroe Bottom Ash Basin is currently inactive, however not closed.
2. Risk of groundwater contamination exists if the CCR material within Area 15 seeks to exists for the long term.

Summary of Scope

- Close Area 15 by removing all CCR material from the basin.

Schedule Assumptions
Construction is targeted for completion by October 31, 2025.

Total Estimated Project Cost: $80,000,000

IRR = N/A (Environmental)

Challenges/Risks to Successful Completion

Timeline to seek full Board of Directors (BOD) approval for this project is targeted for September 2019. This allows for approximately 1-year to develop a design and execution strategy. Schedule compression may be required following BOD approval.

Fos Gen Large Capital Projects Charter

PMP # 15146 **Date: Forecast**

Project Name: Monroe Bottom Ash Basin Closure (CCR)

Investment Planning Rep.: S. Patel

Approver	Initial	Date
Plant Manager: M. Twomley		
Plant Sponsor: J. Good		
Plant Financial Controller: S. Bell		
EM&R Manager: Rob Lee		

Included in Scope

1. Perform geotechnical analysis and engineering for closure by removal.
2. Excavate, dredge and remove CCR material from the Area 15 impoundment.
3. Test and certify that impoundment is clean closed.

Excluded from Scope

1. Investigation or review pertaining to the MONPP Flyash Basin.
2. Engineering or construction pertaining to the process waste water (chem ditch) project. This is to be addressed under a separate project.

Acceptance Criteria

1. Area 15 is certified to be clean closed.

DTE Electric Company

Electric Utilities
(Valuation Metrics)

		Price to Earnings (P/E) Ratio [1]																		
Line	Company	18-Year Average (1)	2019 [2] (2)	2018 (3)	2017 (4)	2016 (5)	2015 (6)	2014 (7)	2013 (8)	2012 (9)	2011 (10)	2010 (11)	2009 (12)	2008 (13)	2007 (14)	2006 (15)	2005 (16)	2004 (17)	2003 (18)	2002 (19)
1	ALLETE	17.74	25.30	15.06	23.05	18.63	15.06	17.23	18.59	15.88	14.66	15.98	16.08	13.95	14.78	16.55	17.91	25.21	N/A	N/A
2	Alliant Energy	16.34	23.40	18.07	20.60	22.30	18.07	16.60	15.28	14.50	14.45	12.47	13.86	13.43	15.08	16.82	12.59	14.00	12.69	19.93
3	Ameren Corp.	16.04	24.00	17.55	20.60	18.29	17.55	16.71	16.52	13.35	11.93	9.66	9.26	14.21	17.45	19.39	16.72	16.28	13.51	15.78
4	American Electric Power	14.46	23.00	15.77	19.33	15.16	15.77	15.88	14.49	13.77	11.92	13.42	10.03	13.06	16.27	12.91	13.70	12.42	10.66	12.68
5	Avangrid, Inc.	30.35	22.10	40.94	27.27	20.49	40.94	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	17.84	16.00	17.60	23.37	18.80	17.60	17.28	14.64	19.30	14.08	12.74	11.42	14.97	30.88	15.39	19.45	24.43	13.84	19.27
7	Black Hills	17.87	22.50	16.14	19.48	22.29	16.14	19.03	18.24	17.13	31.13	18.10	9.93	N/A	15.02	15.77	17.27	17.13	15.95	12.52
8	CenterPoint Energy	14.93	16.90	18.10	17.91	21.91	18.10	16.96	18.75	14.85	14.58	13.78	11.81	11.27	15.00	10.27	19.06	17.84	6.05	5.59
9	CMS Energy Corp.	17.30	24.80	18.29	21.32	20.94	18.29	17.30	16.32	15.07	13.62	12.46	13.56	10.87	26.84	22.18	12.60	12.39	N/A	N/A
10	Consol. Edison	15.56	20.90	15.59	19.77	18.80	15.59	15.90	14.72	15.39	15.08	13.30	12.55	12.29	13.78	15.49	15.13	18.21	14.30	13.28
11	Dominion Resources	18.44	21.00	22.14	22.17	21.33	22.14	22.97	19.25	18.91	17.27	14.35	12.74	13.78	20.63	15.98	24.89	15.07	15.24	12.05
12	DTE Energy	15.78	21.10	18.11	18.59	18.97	18.11	14.91	17.92	14.89	13.51	12.27	10.41	14.81	18.27	17.43	13.80	16.04	13.69	11.28
13	Duke Energy	17.02	17.60	18.22	19.93	21.25	18.22	17.91	17.45	17.46	13.76	12.69	13.32	17.28	16.13	N/A	N/A	N/A	N/A	N/A
14	Edison Int'l	14.01	14.80	14.77	17.23	17.92	14.77	13.05	12.70	9.71	11.81	10.32	9.72	12.36	16.03	12.99	11.74	37.59	6.97	7.78
15	El Paso Electric	17.64	25.50	18.33	21.78	18.66	18.33	16.38	15.88	14.47	12.60	10.72	10.79	11.89	15.26	16.92	26.72	22.03	18.26	22.99
16	Entergy Corp.	13.86	21.80	12.53	15.01	10.92	12.53	12.89	13.21	11.22	9.06	11.57	11.98	16.56	19.30	14.28	16.28	15.09	13.77	11.53
17	Eversource Energy	17.85	22.10	18.11	19.47	18.69	18.11	17.92	16.94	19.86	15.35	13.42	11.96	13.66	18.75	27.07	19.76	20.77	13.35	16.07
18	Evergy, Inc.	22.90	22.90	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	14.32	15.00	12.58	13.41	18.68	12.58	16.02	13.43	19.08	11.30	10.97	11.49	17.97	18.22	16.53	15.37	12.99	11.77	10.46
20	FirstEnergy Corp.	17.24	16.80	17.02	11.41	15.91	17.02	39.79	13.06	21.10	22.39	11.75	13.02	15.64	15.59	14.23	16.07	14.13	22.47	12.95
21	Fortis Inc.	19.28	21.40	18.00	16.81	21.60	18.00	24.29	19.97	20.12	18.79	18.22	16.36	17.48	21.14	17.68	N/A	N/A	N/A	N/A
22	Great Plains Energy	15.76	N/A	19.37	NMF	17.98	19.37	16.47	14.19	15.53	16.11	12.10	16.03	20.55	16.35	18.30	13.96	12.59	12.23	11.09
23	Hawaiian Elec.	18.36	22.30	20.40	20.69	13.56	20.40	15.88	16.21	15.81	17.09	18.59	19.79	23.16	21.57	20.33	18.27	19.18	13.76	13.47
24	IDACORP, Inc.	16.37	23.70	16.22	20.60	19.06	16.22	14.67	13.45	12.41	11.54	11.83	10.20	13.93	18.19	15.07	16.70	15.49	26.51	18.88
25	MGE Energy	18.92	29.30	20.28	29.36	24.90	20.28	17.19	17.01	17.23	15.82	14.98	15.14	14.22	15.01	15.88	22.40	17.98	17.55	15.96
26	NextEra Energy, Inc.	16.36	24.30	16.89	21.65	20.71	16.89	17.25	16.57	14.43	11.54	10.83	13.42	14.48	18.90	13.65	17.88	13.65	17.88	13.60
27	NorthWestern Corp	17.06	19.70	18.36	17.85	17.19	18.36	16.24	16.86	15.72	12.62	12.90	11.54	13.87	21.74	25.95	17.09	N/A	N/A	N/A
28	OGE Energy	15.36	20.60	17.69	18.32	17.68	17.69	18.27	17.69	15.16	14.37	13.31	10.83	12.41	13.75	13.68	14.95	14.13	11.84	14.12
29	Otter Tail Corp.	23.92	23.60	18.20	22.06	20.19	18.20	18.84	21.12	21.75	47.48	55.10	31.16	30.06	19.02	17.35	15.40	17.34	17.77	16.01
30	PG&E Corp.	17.39	N/A	26.40	18.28	21.13	26.40	15.00	23.67	20.70	15.46	15.80	13.01	12.08	16.85	14.84	15.37	13.81	9.50	N/A
31	Pinnacle West Capital	15.77	19.20	16.04	19.28	18.74	16.04	15.89	15.27	14.35	14.60	12.57	13.74	16.07	14.93	13.69	19.24	15.80	13.96	14.43
32	PNM Resources	18.02	22.50	16.85	20.43	19.83	16.85	18.68	16.13	14.97	14.53	14.05	18.09	N/A	35.65	15.57	17.38	15.02	14.73	15.08
33	Portland General	16.69	22.60	17.71	20.03	19.06	17.71	15.32	16.88	13.98	12.37	12.00	14.40	16.30	11.94	23.35	N/A	N/A	N/A	N/A
34	PPL Corp.	14.14	12.00	13.92	17.65	12.83	13.92	14.08	12.84	10.88	10.52	11.93	25.69	17.64	17.26	14.10	15.12	12.51	10.59	11.06
35	Public Serv. Enterprise	13.44	16.10	12.41	16.31	15.35	12.41	12.61	13.50	12.79	10.40	10.37	10.04	13.65	16.54	17.81	16.74	14.26	10.58	10.00
36	SCANA Corp.	14.00	N/A	14.67	14.46	16.80	14.67	13.68	14.43	14.80	13.67	12.93	11.63	12.67	14.96	15.42	14.44	13.57	13.05	12.17
37	Sempra Energy	15.42	23.60	19.73	24.33	24.37	19.73	21.87	19.68	14.89	11.77	12.60	10.09	11.80	14.01	11.50	11.79	8.65	8.96	8.19
38	Southern Co.	15.82	18.00	15.85	15.48	17.76	15.85	16.04	16.19	16.97	15.85	14.90	13.52	16.13	15.95	16.19	15.92	14.68	14.83	14.63
39	Vectren Corp.	17.10	N/A	17.92	23.54	19.18	17.92	19.98	20.66	15.02	15.83	15.10	12.89	16.79	15.33	18.92	15.11	17.57	14.80	14.16
40	WEC Energy Group	16.90	27.90	21.33	20.01	19.95	21.33	17.71	16.50	15.76	14.25	14.01	13.35	14.77	16.47	15.97	14.46	17.51	12.43	10.46
41	Westar Energy	15.75	N/A	18.45	23.40	21.59	18.45	15.36	14.04	13.43	14.78	12.96	14.95	16.96	14.10	12.18	14.79	17.44	10.78	14.02
42	Xcel Energy Inc.	17.12	23.50	16.54	20.20	18.48	16.54	15.44	15.04	14.82	14.24	14.13	12.66	13.69	16.65	14.80	15.36	13.65	11.62	40.80
43	Average	16.62	21.29	18.00	19.81	18.97	18.00	17.39	16.38	15.69	15.30	14.28	13.56	15.18	17.74	16.47	16.52	16.57	13.70	14.31
44	Median	16.05	22.10	17.71	19.97	18.80	17.71	16.54	16.27	15.04	14.31	12.91	12.82	14.21	16.41	15.88	15.92	15.29	13.60	13.47

Sources:
[1] The Value Line Investment Survey Investment Analyzer Software, downloaded on June 25, 2019.
[2] The Value Line Investment Survey, July 26, August 16, and September 13, 2019.

DTE Electric Company

Electric Utilities
(Valuation Metrics)

		Market Price to Cash Flow (MP/CF) Ratio [1]																		
Line	Company	18-Year Average	2019 [2/a]	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007	2006	2005	2004	2003	2002
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
1	ALLETE	9.49	10.74	10.16	10.95	8.26	7.49	8.80	9.15	8.18	7.91	8.04	8.51	9.29	10.30	11.06	11.54	11.46	N/A	N/A
2	Alliant Energy	7.81	10.75	9.71	13.21	10.67	8.86	8.40	7.52	7.50	7.21	6.59	6.23	7.49	7.92	8.00	5.09	5.52	4.76	5.20
3	Ameren Corp.	7.02	9.14	7.95	8.38	7.44	6.87	6.95	6.61	5.48	5.02	4.23	4.25	6.35	7.69	8.57	8.57	8.24	6.74	7.96
4	American Electric Power	6.39	8.83	8.03	8.81	7.57	7.09	7.00	6.57	5.93	5.46	5.54	4.71	5.71	6.84	5.54	6.07	5.50	4.69	5.19
5	Avangrid, Inc.	9.94	9.46	10.24	10.14	8.56	11.30	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	6.74	7.30	10.14	9.35	7.63	6.76	7.30	6.21	6.88	6.40	5.80	4.06	5.12	7.58	5.30	6.58	7.58	5.36	5.90
7	Black Hills	7.76	10.27	8.83	9.20	9.33	8.06	8.81	8.03	6.04	7.85	6.16	4.25	11.26	7.62	6.92	7.57	6.69	6.89	5.92
8	CenterPoint Energy	5.11	6.23	8.45	6.97	5.96	5.75	6.25	6.56	5.15	5.39	4.70	4.05	4.29	5.17	3.94	4.70	4.26	2.08	2.16
9	CMS Energy Corp.	5.85	9.37	8.40	8.75	8.50	7.53	7.13	6.68	6.03	5.41	4.48	3.64	3.45	5.57	4.40	4.04	3.20	2.88	NMF
10	Consol. Edison	8.26	9.41	8.73	9.64	9.39	7.96	7.89	7.77	8.31	8.15	7.39	6.72	6.89	8.31	8.65	8.59	9.31	7.90	7.64
11	Dominion Resources	9.59	12.66	10.94	11.35	11.59	11.84	12.27	10.88	9.92	9.45	8.12	6.98	8.27	8.65	7.81	10.09	7.68	7.51	6.53
12	DTE Energy	6.38	9.46	8.54	9.05	8.64	8.52	6.42	6.65	5.91	5.18	4.69	3.59	4.90	5.73	5.21	5.54	6.00	5.62	5.20
13	Duke Energy	7.58	7.41	7.65	8.40	8.57	7.95	8.12	8.11	9.53	6.56	6.01	5.96	7.13	7.16	N/A	N/A	N/A	N/A	N/A
14	Edison Int'l	5.76	5.81	13.46	7.05	6.77	5.92	5.68	5.46	4.59	4.22	4.11	3.95	5.63	7.01	5.87	5.61	6.84	2.82	2.96
15	El Paso Electric	6.09	8.76	9.43	8.54	7.46	6.47	6.33	6.19	5.78	5.16	4.31	3.98	4.95	6.44	6.25	6.67	4.65	3.90	4.39
16	Entergy Corp.	5.73	6.13	4.92	4.66	4.01	4.11	4.21	4.03	4.23	3.90	4.66	5.68	7.96	9.21	7.16	8.76	7.12	6.84	5.57
17	Eversource Energy	6.83	9.90	9.16	10.36	10.14	10.12	10.14	8.08	9.30	6.99	4.97	4.61	4.12	6.18	6.02	3.55	3.78	2.85	2.75
18	Evergy, Inc.	8.20	8.20	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	6.08	5.17	5.05	4.45	4.80	4.70	5.09	4.61	5.54	5.86	5.10	5.98	9.65	9.89	8.62	7.97	6.29	5.71	4.97
20	FirstEnergy Corp.	6.44	7.87	8.84	4.76	5.12	5.38	7.43	6.15	7.42	7.33	4.49	4.91	7.58	7.89	7.53	6.04	5.15	6.90	5.10
21	Fortis Inc.	8.23	8.81	7.97	8.23	10.46	7.29	9.25	7.93	8.09	8.38	7.40	6.76	7.58	9.18	7.89	N/A	N/A	N/A	N/A
22	Great Plains Energy	6.89	N/A	N/A	14.62	8.63	6.66	6.45	5.73	6.09	5.74	4.49	5.06	7.71	7.13	7.68	6.70	6.52	5.92	5.14
23	Hawaiian Elec.	8.01	8.98	8.34	9.21	7.44	9.25	7.64	8.15	8.05	7.73	7.81	6.95	9.10	7.95	8.47	8.29	8.44	6.12	6.20
24	IDACORP, Inc.	8.35	12.29	11.72	11.56	10.95	9.37	8.59	7.78	7.05	6.64	6.52	5.31	7.10	8.23	7.73	7.55	7.15	7.27	7.53
25	MGE Energy	11.28	14.21	15.04	17.33	15.66	12.53	11.42	11.20	10.77	9.48	9.05	8.40	8.42	9.23	9.30	11.73	11.04	10.20	8.09
26	NextEra Energy, Inc.	7.81	12.44	10.76	11.62	9.23	7.93	7.98	7.60	7.58	5.98	5.33	6.09	7.34	9.02	6.51	6.71	6.71	5.97	5.77
27	NorthWestern Corp	7.66	8.91	8.19	8.82	8.65	8.99	9.01	7.61	6.85	5.89	5.79	5.05	5.57	8.45	9.39	7.31	8.13	N/A	N/A
28	OGE Energy	7.93	10.84	9.36	10.52	9.03	9.25	10.65	9.93	7.35	7.48	6.61	5.37	6.43	7.58	7.50	7.04	6.73	5.62	5.39
29	Otter Tail Corp.	9.42	12.37	11.58	11.09	9.38	9.04	9.45	9.58	8.43	9.04	8.07	8.01	11.65	9.53	8.66	8.18	9.01	8.13	8.33
30	PG&E Corp.	5.55	N/A	- 5.65	7.09	7.26	7.24	5.65	6.84	5.86	5.32	5.42	4.71	4.61	5.84	5.28	5.07	5.13	4.05	14.69
31	Pinnacle West Capital	6.15	7.82	7.09	8.73	7.89	6.91	7.03	6.85	6.34	5.80	5.65	3.84	4.19	4.76	4.48	7.48	5.88	4.80	5.21
32	PNM Resources	6.80	7.98	7.57	7.40	7.64	6.95	7.48	6.47	5.80	4.94	4.58	4.53	7.10	10.67	7.50	7.62	6.84	5.55	5.72
33	Portland General	5.79	7.09	6.56	7.45	7.12	6.73	5.49	6.06	5.08	4.86	4.13	4.63	4.81	5.34	5.74	N/A	N/A	N/A	N/A
34	PPL Corp.	7.47	7.68	7.02	10.11	8.37	8.73	7.32	6.59	5.87	5.98	7.46	8.82	9.17	8.90	7.58	7.57	6.49	5.41	5.30
35	Public Serv. Enterprise	7.48	8.27	9.48	8.67	8.56	6.66	6.48	6.40	6.40	6.03	6.04	6.20	8.46	9.83	8.41	8.59	7.17	6.79	6.24
36	SCANA Corp.	7.09	N/A	N/A	8.26	9.59	8.33	7.50	7.49	7.40	6.75	6.52	5.88	6.38	7.15	7.03	5.40	6.86	6.59	6.36
37	Sempra Energy	7.93	11.07	10.10	10.65	10.88	9.99	10.77	9.37	7.26	6.13	6.53	6.07	7.07	8.61	7.22	6.96	5.16	4.85	4.00
38	Southern Co.	8.13	8.15	7.05	7.49	8.83	8.23	8.42	8.30	8.75	8.22	7.79	7.08	8.18	8.62	8.47	8.41	8.28	8.28	7.83
39	Vectren Corp.	7.08	N/A	N/A	10.32	8.60	7.82	7.57	6.82	5.79	5.81	5.58	5.24	6.90	6.53	7.37	7.06	7.63	7.27	6.92
40	WEC Energy Group	8.64	12.79	10.82	11.04	10.95	12.90	10.27	9.58	9.24	8.43	8.15	6.87	7.57	7.84	7.27	6.40	6.27	4.91	4.27
41	Westar Energy	6.91	N/A	N/A	10.87	10.86	9.05	7.93	7.23	6.71	6.67	5.51	5.32	7.09	6.88	5.81	7.00	6.54	4.24	2.94
42	Xcel Energy Inc.	6.59	8.78	7.90	8.50	8.10	7.62	7.31	7.00	6.85	6.47	6.28	5.43	5.71	6.51	5.54	5.62	5.31	4.27	5.46
43	Average	7.31	9.23	8.64	9.36	8.65	8.05	7.85	7.39	6.98	6.53	6.00	5.59	6.95	7.72	7.12	7.13	6.77	5.70	5.85
44	Median	7.18	8.91	8.73	9.05	8.57	7.93	7.54	7.12	6.85	6.27	5.80	5.35	7.09	7.76	7.37	7.04	6.71	5.62	5.52

Sources:
[1] The Value Line Investment Survey Investment Analyzer Software, downloaded on June 25, 2019.
[2] The Value Line Investment Survey, July 26, August 16, and September 13, 2019.
Note:
[a] Based on the average of the high and low price for 2019 and the projected 2019 Cash Flow per share, published in The Value Line Investment Survey, July 26, August 16, and September 13, 2019.

DTE Electric Company

Electric Utilities
(Valuation Metrics)

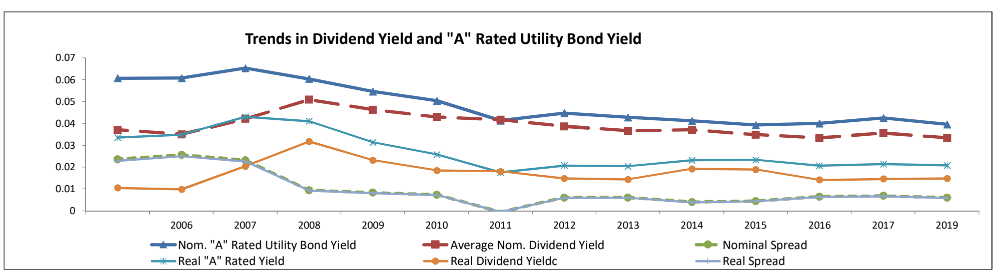
		Market Price to Book Value (MP/BV) Ratio [1]															
Line	Company	15-Year Average	2019 [2/b]	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007	2006	2005
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
1	ALLETE	1.61	1.87	1.79	1.78	1.53	1.37	1.42	1.51	1.34	1.35	1.28	1.15	1.55	1.89	2.09	2.22
2	Alliant Energy	1.70	2.17	2.16	2.38	2.17	1.86	1.86	1.70	1.57	1.46	1.31	1.04	1.33	1.67	1.52	1.33
3	Ameren Corp.	1.45	2.16	1.95	1.93	1.67	1.46	1.45	1.29	1.18	0.90	0.83	0.78	1.25	1.60	1.62	1.68
4	American Electric Power	1.56	2.06	1.82	1.88	1.81	1.55	1.54	1.40	1.31	1.23	1.23	1.08	1.48	1.85	1.56	1.57
5	Avangrid, Inc.	0.90	1.02	1.02	0.93	0.83	0.72	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	1.32	1.50	1.88	1.73	1.57	1.36	1.33	1.25	1.21	1.19	1.07	0.94	1.11	1.29	1.30	1.13
7	Black Hills	1.51	1.85	1.61	2.06	1.94	1.59	1.79	1.62	1.21	1.14	1.07	0.83	1.22	1.57	1.47	1.63
8	CenterPoint Energy	2.34	1.58	2.18	2.59	2.73	2.43	2.27	2.30	1.99	1.87	1.96	1.77	2.49	3.13	2.75	3.06
9	CMS Energy Corp.	2.02	3.14	2.81	2.93	2.72	2.43	2.26	2.09	1.91	1.66	1.48	1.10	1.23	1.82	1.42	1.32
10	Consol. Edison	1.41	1.55	1.49	1.63	1.58	1.42	1.34	1.38	1.47	1.38	1.22	1.08	1.17	1.47	1.47	1.52
11	Dominion Resources	2.62	2.17	2.40	2.94	3.15	3.34	3.55	2.97	2.84	2.37	2.01	1.80	2.42	2.69	2.07	2.50
12	DTE Energy	1.48	1.98	1.91	2.01	1.82	1.65	1.62	1.51	1.35	1.20	1.16	0.89	1.10	1.35	1.29	1.39
13	Duke Energy	1.20	1.41	1.33	1.41	1.35	1.29	1.28	1.19	1.12	1.11	1.00	0.91	1.06	1.15	N/A	N/A
14	Edison Int'l	1.67	1.79	1.97	2.17	1.92	1.76	1.68	1.57	1.53	1.24	1.07	1.04	1.56	2.05	1.80	1.93
15	El Paso Electric	1.59	1.94	1.94	1.87	1.68	1.48	1.52	1.49	1.59	1.64	1.17	0.98	1.33	1.69	1.71	1.76
16	Entergy Corp.	1.74	2.01	1.74	1.76	1.67	1.40	1.33	1.21	1.31	1.35	1.62	1.66	2.44	2.65	1.89	2.01
17	Eversource Energy	1.45	1.88	1.68	1.73	1.64	1.53	1.47	1.38	1.28	1.50	1.31	1.12	1.31	1.60	1.22	1.05
18	Evergy, Inc.	1.58	1.58	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	2.23	1.42	1.31	1.20	1.20	1.14	1.28	1.17	1.46	1.95	2.07	2.57	4.39	4.79	3.89	3.60
20	FirstEnergy Corp.	1.93	2.74	2.67	3.53	2.37	1.16	1.15	1.28	1.44	1.33	1.36	1.54	2.52	2.23	1.92	1.64
21	Fortis Inc.	1.47	1.35	1.24	1.41	1.26	1.33	1.35	1.45	1.59	1.59	1.56	1.33	1.48	1.63	1.96	N/A
22	Great Plains Energy	1.21	N/A	N/A	1.33	1.17	1.12	1.11	1.02	0.96	0.93	0.87	0.80	1.11	1.66	1.77	1.86
23	Hawaiian Elec.	1.64	1.94	1.76	1.76	1.63	1.71	1.49	1.54	1.62	1.54	1.44	1.16	1.61	1.57	2.01	1.78
24	IDACORP, Inc.	1.42	2.00	1.96	1.94	1.76	1.54	1.45	1.33	1.19	1.17	1.13	0.92	1.09	1.26	1.37	1.22
25	MGE Energy	2.08	2.69	2.59	2.88	2.60	2.10	2.10	2.06	1.92	1.75	1.65	1.54	1.62	1.75	1.83	2.09
26	NextEra Energy, Inc.	2.03	2.76	2.32	2.35	2.30	2.09	2.15	1.93	1.74	1.55	1.49	1.70	2.06	2.34	1.80	1.93
27	NorthWestern Corp	1.46	1.65	1.48	1.64	1.68	1.60	1.54	1.56	1.42	1.35	1.22	1.07	1.15	1.48	1.65	1.42
28	OGE Energy	1.85	2.01	1.75	1.82	1.73	1.79	2.22	2.24	1.94	1.90	1.70	1.37	1.52	1.98	1.91	1.80
29	Otter Tail Corp.	1.83	2.59	2.49	2.33	1.90	1.78	1.90	1.96	1.58	1.35	1.19	1.18	1.71	1.93	1.76	1.74
30	PG&E Corp.	1.60	N/A	1.70	1.71	1.69	1.57	1.39	1.38	1.41	1.46	1.56	1.41	1.50	1.94	1.83	1.84
31	Pinnacle West Capital	1.41	1.87	1.74	1.91	1.72	1.52	1.44	1.47	1.39	1.25	1.14	0.95	1.00	1.26	1.26	1.25
32	PNM Resources	1.24	2.21	1.83	1.84	1.56	1.33	1.21	1.09	0.98	0.80	0.69	0.56	0.66	1.23	1.21	1.45
33	Portland General	1.32	1.72	1.56	1.69	1.56	1.42	1.37	1.28	1.14	1.09	0.94	0.92	1.05	1.32	1.36	N/A
34	PPL Corp.	2.12	1.75	1.81	2.40	2.46	2.24	1.64	1.55	1.58	1.47	1.61	2.10	3.19	3.05	2.43	2.50
35	Public Serv. Enterprise	1.91	1.87	1.81	1.68	1.67	1.58	1.57	1.44	1.46	1.59	1.67	1.78	2.58	2.99	2.46	2.45
36	SCANA Corp.	1.51	N/A	N/A	1.65	1.74	1.47	1.48	1.48	1.48	1.36	1.33	1.20	1.45	1.62	1.64	1.72
37	Sempra Energy	1.80	2.07	2.06	2.24	2.00	2.17	2.20	1.84	1.53	1.28	1.35	1.32	1.60	1.87	1.70	1.73
38	Southern Co.	2.04	1.93	1.89	2.07	2.01	1.99	2.02	2.04	2.15	1.99	1.83	1.73	2.12	2.24	2.23	2.35
39	Vectren Corp.	1.83	N/A	N/A	2.75	2.29	2.11	2.08	1.82	1.57	1.53	1.41	1.34	1.64	1.74	1.77	1.82
40	WEC Energy Group	1.92	2.57	2.11	2.10	2.09	1.82	2.34	2.21	2.05	1.81	1.65	1.40	1.57	1.77	1.71	1.62
41	Westar Energy	1.37	N/A	N/A	1.94	1.95	1.49	1.44	1.33	1.26	1.20	1.10	0.93	1.10	1.36	1.30	1.41
42	Xcel Energy Inc.	1.59	2.21	1.97	2.06	1.88	1.66	1.55	1.50	1.51	1.41	1.32	1.19	1.30	1.53	1.40	1.38
43	Average	1.69	1.97	1.88	2.00	1.85	1.67	1.68	1.60	1.51	1.43	1.35	1.25	1.63	1.90	1.78	1.80
44	Median	1.60	1.94	1.83	1.91	1.74	1.57	1.53	1.49	1.47	1.37	1.31	1.15	1.48	1.71	1.71	1.73

Sources:
[1] The Value Line Investment Survey Investment Analyzer Software, downloaded on June 25, 2019.
[2] The Value Line Investment Survey, July 26, August 16, and September 13, 2019.
Notes:
[b] Based on the average of the high and low price for 2018 and the projected 2018 Book Value per share, published in The Value Line Investment Survey, July 26, August 16, and September 13, 2019.

DTE Electric Company

Electric Utilities
(Valuation Metrics)

		Dividend Yield[1]														
Line	Company	14-Year Average (1)	2019 [2/a] (2)	2018 (3)	2017 (4)	2016 (5)	2015 (6)	2014 (7)	2013 (8)	2012 (9)	2011 (10)	2010 (11)	2009 (12)	2008 (13)	2007 (14)	2006 (15)
1	ALLETE	3.95%	2.92%	2.99%	2.97%	3.56%	3.97%	3.92%	3.89%	4.49%	4.58%	5.03%	5.79%	4.37%	3.60%	3.16%
2	Alliant Energy	3.76%	3.00%	3.20%	3.07%	3.21%	3.60%	3.53%	3.74%	4.07%	4.28%	4.61%	5.73%	4.10%	3.13%	3.32%
3	Ameren Corp.	4.50%	2.73%	3.04%	3.12%	3.50%	3.96%	4.02%	4.61%	4.97%	5.28%	5.76%	5.98%	6.21%	4.88%	4.93%
4	American Electric Power	4.09%	3.29%	3.60%	3.42%	3.54%	3.80%	3.83%	4.23%	4.58%	4.96%	4.90%	5.50%	4.20%	3.40%	4.06%
5	Avangrid, Inc.	3.76%	3.51%	3.49%	3.79%	4.26%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	3.75%	3.63%	2.93%	3.14%	3.39%	3.97%	3.99%	4.51%	4.55%	4.54%	4.76%	4.49%	3.39%	2.68%	2.52%
7	Black Hills	3.77%	2.87%	3.31%	2.75%	2.87%	3.55%	2.84%	3.19%	4.39%	4.64%	4.79%	6.17%	4.21%	3.40%	3.79%
8	CenterPoint Energy	4.52%	3.96%	4.09%	4.79%	4.70%	5.06%	3.94%	3.57%	4.04%	4.27%	5.29%	6.37%	4.98%	3.87%	4.39%
9	CMS Energy Corp.	3.27%	2.72%	3.03%	2.88%	2.99%	3.36%	3.59%	3.76%	4.16%	4.25%	3.98%	3.97%	2.69%	1.16%	N/A
10	Consol. Edison	4.45%	3.61%	3.68%	3.40%	3.62%	4.12%	4.38%	4.25%	4.07%	4.46%	5.16%	5.99%	5.67%	4.84%	5.04%
11	Dominion Resources	4.06%	5.00%	4.72%	3.88%	3.82%	3.66%	3.43%	3.78%	4.06%	4.13%	4.41%	5.20%	3.77%	3.32%	3.60%
12	DTE Energy	4.17%	3.22%	3.34%	3.15%	3.34%	3.53%	3.54%	3.84%	4.19%	4.68%	4.75%	6.29%	5.24%	4.36%	4.86%
13	Duke Energy	4.75%	4.31%	4.54%	4.15%	4.26%	4.34%	4.26%	4.45%	4.68%	5.21%	5.71%	6.25%	5.16%	4.44%	N/A
14	Edison Int'l	3.08%	3.92%	3.84%	2.87%	2.81%	2.83%	2.62%	2.85%	2.97%	3.37%	3.66%	3.95%	2.69%	2.21%	2.58%
15	El Paso Electric	2.73%	2.65%	2.55%	2.49%	2.75%	3.13%	2.97%	2.99%	2.97%	2.11%	N/A	N/A	N/A	N/A	N/A
16	Entergy Corp.	4.10%	3.69%	4.41%	4.49%	4.55%	4.59%	4.47%	5.07%	4.91%	4.85%	4.20%	3.97%	2.92%	2.39%	2.82%
17	Eversource Energy	3.33%	3.02%	3.32%	3.14%	3.22%	3.34%	3.40%	3.48%	3.52%	3.23%	3.64%	4.16%	3.25%	2.60%	3.27%
18	Evergy, Inc.	3.22%	3.22%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	3.85%	3.06%	3.32%	3.51%	3.75%	3.88%	3.69%	4.69%	5.73%	4.96%	4.95%	4.26%	2.78%	2.48%	2.83%
20	FirstEnergy Corp.	4.38%	3.75%	5.17%	4.62%	4.31%	4.23%	4.26%	4.26%	4.90%	5.23%	5.76%	5.09%	3.21%	3.12%	3.40%
21	Fortis Inc.	3.68%	3.69%	4.07%	3.69%	3.80%	3.76%	3.88%	3.84%	3.64%	3.58%	3.80%	4.21%	3.76%	3.01%	2.79%
22	Great Plains Energy	4.52%	N/A	N/A	3.58%	3.64%	3.76%	3.62%	3.84%	4.08%	4.15%	4.49%	5.03%	6.96%	5.49%	5.60%
23	Hawaiian Elec.	4.63%	3.20%	3.54%	3.65%	3.99%	4.05%	4.76%	4.72%	4.70%	5.04%	5.51%	6.89%	5.00%	5.18%	4.59%
24	IDACORP, Inc.	3.22%	2.62%	2.61%	2.58%	2.77%	3.06%	3.12%	3.21%	3.28%	3.10%	3.44%	4.46%	3.95%	3.55%	3.39%
25	MGE Energy	3.19%	2.07%	2.16%	1.95%	2.23%	2.78%	2.78%	2.91%	3.25%	3.63%	3.98%	4.36%	4.24%	4.14%	4.25%
26	NextEra Energy, Inc.	3.17%	2.62%	2.68%	2.79%	2.91%	3.01%	3.00%	3.30%	3.65%	3.96%	3.90%	3.55%	3.02%	2.65%	3.40%
27	NorthWestern Corp	4.10%	3.49%	3.86%	3.52%	3.43%	3.61%	3.30%	3.66%	4.17%	4.51%	4.93%	5.75%	5.38%	4.09%	3.65%
28	OGE Energy	3.62%	3.69%	3.98%	3.61%	3.87%	3.51%	2.63%	2.48%	2.94%	3.06%	3.68%	4.96%	4.52%	3.77%	3.99%
29	Otter Tail Corp.	4.15%	2.79%	2.92%	3.12%	3.87%	4.33%	4.14%	4.11%	5.21%	5.57%	5.68%	5.38%	3.63%	3.46%	3.92%
30	PG&E Corp.	3.70%	N/A	N/A	2.42%	3.22%	3.45%	3.96%	4.20%	4.25%	4.24%	4.08%	4.26%	4.01%	3.07%	3.22%
31	Pinnacle West Capital	4.53%	3.35%	3.55%	3.16%	3.46%	3.88%	4.09%	3.98%	5.32%	4.81%	5.43%	6.76%	6.17%	4.75%	4.67%
32	PNM Resources	3.26%	2.57%	2.79%	2.53%	2.69%	2.90%	2.79%	2.99%	2.96%	3.19%	4.09%	4.76%	4.85%	3.36%	3.21%
33	Portland General	3.70%	3.04%	3.27%	2.92%	3.06%	3.27%	3.34%	3.67%	4.11%	4.37%	5.20%	5.36%	4.28%	3.34%	2.54%
34	PPL Corp.	4.45%	5.44%	5.61%	4.24%	4.25%	4.55%	4.45%	4.81%	5.07%	5.10%	5.12%	4.51%	3.10%	2.69%	3.41%
35	Public Serv. Enterprise	3.81%	3.37%	3.49%	3.74%	3.78%	3.81%	3.92%	4.35%	4.55%	4.24%	4.30%	4.30%	3.26%	2.73%	3.47%
36	SCANA Corp.	4.37%	N/A	N/A	4.03%	3.29%	3.90%	4.05%	4.15%	4.25%	4.78%	4.93%	5.67%	4.92%	4.29%	4.21%
37	Sempra Energy	2.95%	3.12%	3.20%	2.92%	2.92%	2.71%	2.61%	3.03%	3.71%	3.65%	3.08%	3.23%	2.62%	2.08%	2.47%
38	Southern Co.	4.74%	4.87%	5.27%	4.63%	4.42%	4.78%	4.69%	4.61%	4.29%	4.63%	5.13%	5.52%	4.58%	4.39%	4.52%
39	Vectren Corp.	4.38%	N/A	N/A	2.79%	3.31%	3.60%	3.62%	4.15%	4.82%	5.06%	5.53%	5.85%	4.79%	4.53%	4.52%
40	WEC Energy Group	3.05%	2.86%	3.38%	3.31%	3.35%	3.49%	3.40%	3.49%	3.24%	3.35%	2.97%	3.16%	2.41%	2.14%	2.18%
41	Westar Energy	4.37%	N/A	N/A	3.00%	2.90%	3.73%	3.88%	4.27%	4.57%	4.84%	5.32%	6.27%	5.22%	4.16%	4.28%
42	Xcel Energy Inc.	3.93%	2.95%	3.25%	3.10%	3.33%	3.69%	3.83%	3.86%	3.90%	4.20%	4.54%	5.14%	4.70%	4.05%	4.40%
43	**Average**	**3.90%**	**3.35%**	**3.56%**	**3.34%**	**3.49%**	**3.71%**	**3.66%**	**3.87%**	**4.18%**	**4.30%**	**4.63%**	**5.09%**	**4.21%**	**3.51%**	**3.71%**
44	Median	3.87%	3.22%	3.36%	3.15%	3.43%	3.71%	3.76%	3.85%	4.18%	4.42%	4.76%	5.14%	4.21%	3.40%	3.60%
45	20-Yr Treasury Yields[3]	3.41%	2.57%	3.02%	2.65%	2.23%	2.55%	3.07%	3.12%	2.54%	3.62%	4.03%	4.11%	4.36%	4.91%	4.99%
46	20-Yr TIPS[3]	1.26%	0.73%	0.94%	0.75%	0.66%	0.78%	0.87%	0.75%	0.21%	1.19%	1.73%	2.21%	2.19%	2.36%	2.31%
47	Implied Inflation[b]	2.12%	1.83%	2.06%	1.89%	1.56%	1.75%	2.19%	2.35%	2.33%	2.40%	2.26%	1.85%	2.13%	2.49%	2.62%
48	**Real Dividend Yield[c]**	**1.74%**	**1.48%**	**1.47%**	**1.42%**	**1.90%**	**1.93%**	**1.44%**	**1.49%**	**1.81%**	**1.86%**	**2.32%**	**3.18%**	**2.04%**	**0.99%**	**1.06%**
	Utility															
49	**Nominal "A" Rated Yield[4]**	**4.88%**	**3.95%**	**4.25%**	**4.00%**	**3.93%**	**4.12%**	**4.28%**	**4.48%**	**4.13%**	**5.04%**	**5.46%**	**6.04%**	**6.53%**	**6.07%**	**6.07%**
50	**Real "A" Rated Yield**	**2.70%**	**2.08%**	**2.14%**	**2.07%**	**2.34%**	**2.33%**	**2.04%**	**2.08%**	**1.76%**	**2.58%**	**3.13%**	**4.11%**	**4.31%**	**3.49%**	**3.36%**
	Spreads (Utility Bond - Stock)															
51	**Nominal Spread[d]**	**0.98%**	**0.61%**	**0.69%**	**0.66%**	**0.44%**	**0.40%**	**0.61%**	**0.61%**	**-0.05%**	**0.74%**	**0.84%**	**0.95%**	**2.32%**	**2.57%**	**2.36%**
52	**Real Spread[e]**	**0.96%**	**0.60%**	**0.68%**	**0.65%**	**0.44%**	**0.40%**	**0.60%**	**0.59%**	**-0.05%**	**0.72%**	**0.82%**	**0.93%**	**2.27%**	**2.50%**	**2.30%**
	Spreads (Treasury Bond - Stock)															
53	**Nominal[f]**	**-0.49%**	**-0.77%**	**-0.54%**	**-0.69%**	**-1.26%**	**-1.17%**	**-0.59%**	**-0.75%**	**-1.64%**	**-0.68%**	**-0.60%**	**-0.98%**	**0.15%**	**1.40%**	**1.28%**
54	**Real[g]**	**-0.48%**	**-0.76%**	**-0.53%**	**-0.68%**	**-1.24%**	**-1.15%**	**-0.58%**	**-0.73%**	**-1.60%**	**-0.67%**	**-0.58%**	**-0.97%**	**0.15%**	**1.37%**	**1.25%**



Sources:
[1] The Value Line Investment Survey Investment Analyzer Software, downloaded on June 25, 2019.
[2] The Value Line Investment Survey, July 26, August 16, and September 13, 2019.
[3] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org.
[4] www.moodys.com, Bond Yields and Key Indicators, through August 30, 2019.
Notes:
[a] Based on the average of the high and low price for 2017 and the projected 2017 Dividends Declared per share, published in the Value Line Investment Survey, July 26, August 16, and September 13, 2019.
[b] Line 47 = (1 + Line 45) / (1 + Line 46) - 1.
[c] Line 48 = (1 + Line 43) / (1 +Line 47) - 1.
[d] The spread being measured here is the nominal A-rated utility bond yield over the average nominal utility dividend yield; (Line 49 - Line 43).
[e] The spread being measured here is the real A-rated utility bond yield over the average real utility dividend yield; Line 50 - Line 48)
[f] The spread being measured here is the nominal 20-Year Treasury yield over the average nominal utility dividend yield; (Line 45 - Line 43).
[g] The spread being measured here is the real 20-Year TIPS yield over the average real utility dividend yield; Line 48 - Line 46)

DTE Electric Company

Electric Utilities
(Valuation Metrics)

		Dividend per Share[1]														
Line	Company	14-Year Average (1)	2019[2] (2)	2018 (3)	2017 (4)	2016 (5)	2015 (6)	2014 (7)	2013 (8)	2012 (9)	2011 (10)	2010 (11)	2009 (12)	2008 (13)	2007 (14)	2006 (15)
1	ALLETE	1.90	2.35	2.24	2.14	2.08	2.02	1.96	1.90	1.84	1.78	1.76	1.76	1.72	1.64	1.45
2	Alliant Energy	0.96	1.42	1.34	1.26	1.18	1.10	1.02	0.94	0.90	0.85	0.79	0.75	0.70	0.64	0.58
3	Ameren Corp.	1.86	1.93	1.85	1.78	1.72	1.66	1.61	1.60	1.60	1.56	1.54	1.54	2.54	2.54	2.54
4	American Electric Power	1.99	2.72	2.53	2.39	2.27	2.15	2.03	1.95	1.88	1.85	1.71	1.64	1.64	1.58	1.50
5	Avangrid, Inc.	1.74	1.76	1.74	1.73	1.73	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	1.11	1.55	1.49	1.43	1.37	1.32	1.27	1.22	1.16	1.10	1.00	0.81	0.69	0.60	0.57
7	Black Hills	1.58	2.05	1.93	1.81	1.68	1.62	1.56	1.52	1.48	1.46	1.44	1.42	1.40	1.37	1.32
8	CenterPoint Energy	0.90	1.16	1.12	1.35	1.03	0.99	0.95	0.83	0.81	0.79	0.78	0.76	0.73	0.68	0.60
9	CMS Energy Corp.	0.95	1.53	1.43	1.33	1.24	1.16	1.08	1.02	0.96	0.84	0.66	0.50	0.36	0.20	N/A
10	Consol. Edison	2.53	2.96	2.86	2.76	2.68	2.60	2.52	2.46	2.42	2.40	2.38	2.36	2.34	2.32	2.30
11	Dominion Resources	2.30	3.67	3.34	3.04	2.80	2.59	2.40	2.25	2.11	1.97	1.83	1.75	1.58	1.46	1.38
12	DTE Energy	2.67	3.85	3.59	3.36	3.06	2.84	2.69	2.59	2.42	2.32	2.18	2.12	2.12	2.12	2.08
13	Duke Energy	3.13	3.75	3.64	3.49	3.36	3.24	3.15	3.09	3.03	2.97	2.91	2.82	2.70	2.58	N/A
14	Edison Int'l	1.59	2.45	2.43	2.23	1.98	1.73	1.48	1.37	1.31	1.29	1.27	1.25	1.23	1.18	1.10
15	El Paso Electric	1.16	1.52	1.42	1.32	1.23	1.17	1.11	1.05	0.97	0.66	N/A	N/A	N/A	N/A	N/A
16	Entergy Corp.	3.20	3.66	3.58	3.50	3.42	3.34	3.32	3.32	3.32	3.32	3.24	3.00	3.00	2.58	2.16
17	Eversource Energy	1.38	2.14	2.02	1.90	1.78	1.67	1.57	1.47	1.32	1.10	1.03	0.95	0.83	0.78	0.73
18	Evergy, Inc.	1.94	1.94	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	1.66	1.45	1.38	1.31	1.26	1.24	1.24	1.46	2.10	2.10	2.10	2.10	2.05	1.82	1.64
20	FirstEnergy Corp.	1.83	1.52	1.82	1.44	1.44	1.44	1.44	1.65	2.20	2.20	2.20	2.20	2.20	2.05	1.85
21	Fortis Inc.	1.27	1.85	1.75	1.65	1.55	1.43	1.30	1.25	1.21	1.17	1.12	1.04	1.00	0.82	0.67
22	Great Plains Energy	1.11	N/A	N/A	1.10	1.06	1.00	0.94	0.88	0.86	0.84	0.83	0.83	1.66	1.66	1.66
23	Hawaiian Elec.	1.24	1.28	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24
24	IDACORP, Inc.	1.65	2.56	2.40	2.24	2.08	1.92	1.76	1.57	1.37	1.20	1.20	1.20	1.20	1.20	1.20
25	MGE Energy	1.10	1.38	1.32	1.26	1.21	1.16	1.11	1.07	1.04	1.01	0.99	0.97	0.96	0.94	0.93
26	NextEra Energy, Inc.	2.78	5.00	4.44	3.93	3.48	3.08	2.90	2.64	2.40	2.20	2.00	1.89	1.78	1.64	1.50
27	NorthWestern Corp	1.65	2.30	2.20	2.10	2.00	1.92	1.60	1.52	1.48	1.44	1.36	1.34	1.32	1.28	1.24
28	OGE Energy	0.95	1.52	1.40	1.27	1.16	1.05	0.95	0.85	0.80	0.76	0.73	0.71	0.70	0.68	0.67
29	Otter Tail Corp.	1.23	1.40	1.34	1.28	1.25	1.23	1.21	1.19	1.19	1.19	1.19	1.19	1.19	1.17	1.15
30	PG&E Corp.	1.70	N/A	N/A	1.55	1.93	1.82	1.82	1.82	1.82	1.82	1.82	1.68	1.56	1.44	1.32
31	Pinnacle West Capital	2.38	3.04	2.87	2.70	2.56	2.44	2.33	2.23	2.67	2.10	2.10	2.10	2.10	2.10	2.03
32	PNM Resources	0.77	1.18	1.09	0.99	0.88	0.80	0.76	0.68	0.58	0.50	0.50	0.50	0.61	0.91	0.86
33	Portland General	1.12	1.52	1.43	1.34	1.26	1.18	1.12	1.10	1.08	1.06	1.04	1.01	0.97	0.93	0.68
34	PPL Corp.	1.44	1.65	1.64	1.58	1.52	1.50	1.49	1.47	1.44	1.40	1.40	1.38	1.34	1.22	1.10
35	Public Serv. Enterprise	1.47	1.88	1.80	1.72	1.64	1.56	1.48	1.44	1.42	1.37	1.37	1.33	1.29	1.17	1.14
36	SCANA Corp.	2.00	N/A	N/A	2.45	2.30	2.18	2.10	2.03	1.98	1.94	1.90	1.88	1.84	1.76	1.68
37	Sempra Energy	2.36	3.87	3.58	3.29	3.02	2.80	2.64	2.52	2.40	1.92	1.56	1.56	1.37	1.24	1.20
38	Southern Co.	1.98	2.46	2.38	2.30	2.22	2.15	2.08	2.01	1.94	1.87	1.80	1.73	1.66	1.60	1.54
39	Vectren Corp.	1.42	N/A	N/A	1.71	1.62	1.54	1.46	1.43	1.41	1.39	1.37	1.35	1.31	1.27	1.23
40	WEC Energy Group	1.33	2.36	2.21	2.08	1.98	1.74	1.56	1.45	1.20	1.04	0.80	0.68	0.54	0.50	0.46
41	Westar Energy	1.30	N/A	N/A	1.60	1.52	1.44	1.40	1.36	1.32	1.28	1.24	1.20	1.16	1.08	0.98
42	Xcel Energy Inc.	1.17	1.62	1.52	1.44	1.36	1.28	1.20	1.11	1.07	1.03	1.00	0.97	0.94	0.91	0.88
43	**Average**	**1.66**	**2.22**	**2.12**	**1.97**	**1.86**	**1.76**	**1.67**	**1.61**	**1.59**	**1.51**	**1.47**	**1.42**	**1.42**	**1.36**	**1.27**
44	**Industry Average Growth**	**4.40%**	**4.83%**	**7.61%**	**6.14%**	**5.60%**	**5.24%**	**3.58%**	**1.23%**	**5.69%**	**2.49%**	**3.36%**	**-0.08%**	**5.06%**	**6.45%**	

Sources:
[1] The Value Line Investment Survey Investment Analyzer Software, downloaded on June 25, 2019.
[2] The Value Line Investment Survey, July 26, August 16, and September 13, 2019.
Notes:
PG&E is excluded from 2017, 2018 and 2019 average calculations due to their Dividend Suspension.

DTE Electric Company

Electric Utilities
(Valuation Metrics)

		Earnings per Share[1]														
Line	Company	14-Year Average (1)	2019 [2] (2)	2018 (3)	2017 (4)	2016 (5)	2015 (6)	2014 (7)	2013 (8)	2012 (9)	2011 (10)	2010 (11)	2009 (12)	2008 (13)	2007 (14)	2006 (15)
1	ALLETE	2.85	3.40	3.38	3.13	3.14	3.38	2.90	2.63	2.58	2.65	2.19	1.89	2.82	3.08	2.77
2	Alliant Energy	1.57	2.25	2.19	1.99	1.65	1.69	1.74	1.65	1.53	1.38	1.38	0.95	1.27	1.35	1.03
3	Ameren Corp.	2.71	3.30	3.32	2.77	2.68	2.38	2.40	2.10	2.41	2.47	2.77	2.78	2.88	2.98	2.66
4	American Electric Power	3.31	4.10	3.90	3.62	4.23	3.59	3.34	3.18	2.98	3.13	2.60	2.97	2.99	2.86	2.86
5	Avangrid, Inc.	1.73	2.20	1.92	1.67	1.98	0.86	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	1.74	2.85	2.07	1.95	2.15	1.89	1.84	1.85	1.32	1.72	1.65	1.58	1.36	0.72	1.47
7	Black Hills	2.39	3.55	3.47	3.38	2.63	2.83	2.89	2.61	1.97	1.01	1.66	2.32	0.18	2.68	2.21
8	CenterPoint Energy	1.22	1.50	0.74	1.57	1.00	1.08	1.42	1.24	1.35	1.27	1.07	1.01	1.30	1.17	1.33
9	CMS Energy Corp.	1.57	2.50	2.32	2.17	1.98	1.89	1.74	1.66	1.53	1.45	1.33	0.93	1.23	0.64	0.64
10	Consol. Edison	3.72	4.05	4.55	4.10	3.94	4.05	3.62	3.93	3.86	3.57	3.47	3.14	3.36	3.48	2.95
11	Dominion Resources	2.87	2.00	3.25	3.53	3.44	3.20	3.05	3.09	2.75	2.76	2.89	2.64	3.04	2.13	2.40
12	DTE Energy	4.19	6.25	6.17	5.73	4.83	4.44	5.10	3.76	3.88	3.67	3.74	3.24	2.73	2.66	2.45
13	Duke Energy	3.85	5.00	4.13	4.22	3.71	4.10	4.13	3.98	3.71	4.14	4.02	3.39	3.03	3.60	2.73
14	Edison Int'l	3.49	4.75	-1.26	4.51	3.94	4.15	4.33	3.78	4.55	3.23	3.35	3.24	3.68	3.32	3.28
15	El Paso Electric	2.07	2.60	2.07	2.42	2.39	2.03	2.27	2.20	2.26	2.48	2.07	1.50	1.73	1.63	1.27
16	Entergy Corp.	5.98	5.60	5.88	5.19	6.88	5.81	5.77	4.96	6.02	7.55	6.66	6.30	6.20	5.60	5.36
17	Eversource Energy	2.36	3.45	3.25	3.11	2.96	2.76	2.58	2.49	1.89	2.22	2.10	1.91	1.86	1.59	0.82
18	Evergy, Inc.	2.80	2.80	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	3.00	3.00	2.07	2.78	1.80	2.54	2.10	2.31	1.92	3.75	3.87	4.29	4.10	4.03	3.50
20	FirstEnergy Corp.	2.68	2.55	1.33	2.73	2.10	2.00	0.85	2.97	2.13	1.88	3.25	3.32	4.38	4.22	3.82
21	Fortis Inc.	1.82	2.60	2.52	2.66	1.89	2.11	1.38	1.63	1.65	1.74	1.62	1.51	1.52	1.29	1.36
22	Great Plains Energy	1.33	N/A	N/A	-0.06	1.61	1.37	1.57	1.62	1.35	1.25	1.53	1.03	1.16	1.85	1.62
23	Hawaiian Elec.	1.52	2.00	1.85	1.64	2.29	1.50	1.64	1.62	1.67	1.44	1.21	0.91	1.07	1.11	1.33
24	IDACORP, Inc.	3.37	4.40	4.49	4.21	3.94	3.87	3.85	3.64	3.37	3.36	2.95	2.64	2.18	1.86	2.35
25	MGE Energy	1.94	2.60	2.43	2.20	2.18	2.06	2.32	2.16	1.86	1.76	1.67	1.47	1.59	1.51	1.37
26	NextEra Energy, Inc.	5.13	7.75	6.67	6.50	5.78	6.06	5.60	4.83	4.56	4.82	4.74	3.97	4.07	3.27	3.23
27	NorthWestern Corp	2.55	3.70	3.40	3.34	3.39	2.90	2.99	2.46	2.26	2.53	2.14	2.02	1.77	1.44	1.31
28	OGE Energy	1.68	2.10	2.12	1.92	1.69	1.69	1.98	1.94	1.79	1.73	1.50	1.33	1.25	1.32	1.23
29	Otter Tail Corp.	1.38	2.15	2.06	1.86	1.60	1.56	1.55	1.37	1.05	0.45	0.38	0.71	1.09	1.78	1.69
30	PG&E Corp.	1.49	N/A	-13.25	3.50	2.83	2.00	3.06	1.83	2.07	2.78	2.82	3.03	3.22	2.78	2.76
31	Pinnacle West Capital	3.50	4.85	4.54	4.43	3.95	3.92	3.58	3.66	3.50	2.99	3.08	2.26	2.12	2.96	3.17
32	PNM Resources	1.31	2.20	1.66	1.92	1.65	1.64	1.45	1.41	1.31	1.08	0.87	0.58	0.11	0.76	1.72
33	Portland General	1.92	2.45	2.37	2.29	2.16	2.04	2.18	1.77	1.87	1.95	1.66	1.31	1.39	2.33	1.14
34	PPL Corp.	2.36	2.40	2.58	2.11	2.79	2.37	2.38	2.38	2.61	2.61	2.29	1.19	2.45	2.63	2.29
35	Public Serv. Enterprise	2.86	3.80	2.76	2.82	2.83	3.30	2.99	2.45	2.44	3.11	3.07	3.08	2.90	2.59	1.85
36	SCANA Corp.	3.30	N/A	N/A	4.20	4.16	3.81	3.79	3.39	3.15	2.97	2.98	2.85	2.95	2.74	2.59
37	Sempra Energy	4.63	5.90	5.48	4.63	4.24	5.23	4.63	4.22	4.35	4.47	4.02	4.78	4.43	4.26	4.23
38	Southern Co.	2.64	3.05	3.00	3.21	2.83	2.84	2.77	2.70	2.67	2.55	2.36	2.32	2.25	2.28	2.10
39	Vectren Corp.	1.94	N/A	N/A	2.60	2.55	2.39	2.02	1.66	1.94	1.73	1.64	1.79	1.63	1.83	1.44
40	WEC Energy Group	2.34	3.53	3.34	3.14	2.96	2.34	2.59	2.51	2.35	2.18	1.92	1.60	1.52	1.42	1.32
41	Westar Energy	1.96	N/A	N/A	2.27	2.43	2.09	2.35	2.27	2.15	1.79	1.80	1.28	1.31	1.84	1.88
42	Xcel Energy Inc.	1.89	2.60	2.47	2.30	2.21	2.10	2.03	1.91	1.85	1.72	1.56	1.49	1.46	1.35	1.35
43	**Average**	**2.64**	**3.40**	**3.01**	**3.02**	**2.91**	**2.78**	**2.77**	**2.60**	**2.51**	**2.53**	**2.45**	**2.26**	**2.29**	**2.32**	**2.17**
44	**Indsutry Average Growth**	**3.59%**	**12.80%**	**-0.18%**	**3.68%**	**4.86%**	**0.28%**	**6.70%**	**3.34%**	**-0.86%**	**3.54%**	**8.08%**	**-1.11%**	**-1.47%**	**6.98%**	

Sources:
[1] The Value Line Investment Survey Investment Analyzer Software, downloaded on June 25, 2019.
[2] The Value Line Investment Survey, July 26, August 16, and September 13, 2019.
Notes:
PG&E is excluded from 2017, 2018, and 2019 average calculations due to their Dividend Suspension.

DTE Electric Company

Electric Utilities
(Valuation Metrics)

		Cash Flow / Capital Spending				
Line	Company	2017 (1)	2018 (2)	2019 (3)	2020 (4)	3 - 5 yr Projection (5)
1	ALLETE	1.61x	1.22x	0.71x	1.10x	1.71x
2	Alliant Energy	0.49x	N/A	0.65x	0.71x	0.85x
3	Ameren Corp.	0.75x	0.80x	0.79x	0.62x	0.98x
4	American Electric Power	0.67x	0.68x	0.69x	0.78x	0.88x
5	Avangrid, Inc.	0.57x	0.85x	0.68x	0.56x	0.69x
6	Avista Corp.	0.77x	0.78x	0.94x	0.86x	1.00x
7	Black Hills	1.17x	0.87x	0.55x	0.77x	1.22x
8	CenterPoint Energy	1.22x	0.98x	0.97x	1.05x	1.15x
9	CMS Energy Corp.	0.89x	0.77x	0.78x	0.76x	1.00x
10	Consol. Edison	0.76x	0.82x	0.80x	0.77x	0.90x
11	Dominion Resources	0.81x	1.04x	0.78x	1.00x	1.23x
12	DTE Energy	0.94x	0.84x	0.65x	1.05x	1.23x
13	Duke Energy	0.87x	0.81x	0.78x	0.86x	1.08x
14	Edison Int'l	0.94x	0.34x	0.73x	0.78x	0.83x
15	El Paso Electric	1.04x	0.86x	0.94x	1.01x	0.94x
16	Entergy Corp.	0.76x	0.73x	0.70x	0.85x	0.89x
17	Eversource Energy	0.79x	0.83x	0.78x	0.95x	1.26x
18	Evergy, Inc.	N/A	1.17x	1.29x	1.31x	1.65x
19	Exelon Corp.	1.06x	1.05x	1.20x	1.32x	1.52x
20	FirstEnergy Corp.	1.03x	0.76x	0.94x	1.02x	1.19x
21	Fortis Inc.	0.76x	0.72x	0.58x	0.77x	0.87x
22	Hawaiian Elec.	0.81x	0.85x	1.14x	1.12x	1.17x
23	IDACORP, Inc.	1.33x	1.42x	1.25x	1.27x	1.31x
24	MGE Energy	1.19x	0.66x	0.80x	1.13x	1.21x
25	NextEra Energy, Inc.	0.53x	0.56x	0.82x	0.94x	1.13x
26	NorthWestern Corp	1.21x	1.23x	1.11x	1.11x	1.38x
27	OGE Energy	0.81x	1.30x	1.21x	1.40x	1.58x
28	Otter Tail Corp.	1.10x	1.49x	0.73x	0.46x	1.36x
29	PG&E Corp.	0.82x	-0.58x	N/A	N/A	N/A
30	Pinnacle West Capital	0.76x	1.06x	1.04x	1.11x	1.21x
31	PNM Resources	0.84x	0.82x	0.72x	0.69x	0.90x
32	Portland General	1.07x	1.00x	1.05x	1.05x	1.59x
33	PPL Corp.	0.82x	0.93x	0.92x	1.06x	1.54x
34	Public Serv. Enterprise	0.64x	0.70x	1.13x	1.10x	1.29x
35	Sempra Energy	0.67x	0.80x	0.66x	0.93x	1.46x
36	Southern Co.	0.90x	0.83x	0.87x	1.01x	1.38x
37	WEC Energy Group	0.92x	0.90x	0.68x	0.68x	1.10x
38	Xcel Energy Inc.	0.84x	0.77x	0.68x	0.96x	1.10x
39	Average	0.90x	0.86x	0.86x	0.94x	1.18x
40	Median	0.84x	0.83x	0.79x	0.96x	1.19x

Sources:
The Value Line Investment Survey Investment Analyzer Software, downloaded on June 25, 2019.
The Value Line Investment Survey, July 26, August 16, and September 13, 2019.

Notes:
Based on the projected Cash Flow per share and Capital Spending per share.

DTE Electric Company

Proxy Group

Line	Company	Credit Ratings[1] S&P (1)	Credit Ratings[1] Moody's (2)	Common Equity Ratios MI[1] (3)	Common Equity Ratios Value Line[2] (4)
1	ALLETE, Inc.	BBB+	Baa1	59.2%	60.1%
2	Alliant Energy Corporation	A-	Baa1	42.7%	46.7%
3	American Electric Power Company, Inc.	A-	Baa1	42.6%	46.8%
4	Ameren Corporation	BBB+	Baa1	45.4%	48.8%
5	Avangrid, Inc.	BBB+	Baa1	69.4%	73.8%
6	CMS Energy Corporation	BBB+	Baa1	28.7%	30.7%
7	Consolidated Edison, Inc.	A-	Baa1	44.5%	48.9%
8	DTE Energy Company	BBB+	Baa1	41.0%	45.8%
9	Duke Energy Corporation	A-	Baa1	43.1%	46.2%
10	Edison International	BBB	Baa3	37.2%	38.3%
11	Entergy Corporation	BBB+	Baa2	32.5%	35.9%
12	Eversource Energy	A-	Baa1	43.7%	46.9%
13	IDACORP, Inc.	BBB	Baa1	56.3%	56.4%
14	MGE Energy, Inc.	N/A	N/A	61.5%	62.3%
15	NextEra Energy, Inc.	A-	Baa1	45.0%	56.0%
16	OGE Energy Corp.	BBB+	Baa1	56.0%	58.0%
17	Otter Tail Corporation	BBB	Baa2	54.5%	55.3%
18	Pinnacle West Capital Corporation	A-	A3	49.4%	53.0%
19	PNM Resources, Inc.	BBB+	Baa3	36.2%	38.6%
20	Portland General Electric Company	BBB+	A3	50.3%	53.5%
21	PPL Corporation	A-	Baa2	34.6%	36.7%
22	Public Service Enterprise Group Incorporated	BBB+	Baa1	48.2%	52.2%
23	Southern Company	A-	Baa2	32.5%	37.6%
24	Xcel Energy Inc.	A-	Baa1	41.5%	43.6%
25	**Average**	**BBB+**	**Baa1**	**45.7%**	**48.8%**
26	**Median**			**44.1%**	**47.9%**
27	**DTE Electric Company**	**A-**	**A2**		**50.0%**[3]

Sources:
[1] S&P Global Market Intelligence, Downloaded on October 7, 2019.
[2] *The Value Line Investment Survey*, July 26, August 16, and September 13, 2019.
[3] Solomon direct at EJS-5.

DTE Electric Company

Consensus Analysts' Growth Rates

		Zacks		MI		Yahoo! Finance		Average of
Line	**Company**	**Estimated Growth %[1]** (1)	**Number of Estimates** (2)	**Estimated Growth %[2]** (3)	**Number of Estimates** (4)	**Estimated Growth %[3]** (5)	**Number of Estimates** (6)	**Growth Rates** (7)
1	ALLETE, Inc.	7.20%	N/A	7.07%	3	6.00%	6	6.76%
2	Alliant Energy Corporation	5.50%	N/A	5.66%	4	5.05%	10	5.40%
3	American Electric Power Company, Inc.	5.70%	N/A	5.82%	7	6.10%	19	5.87%
4	Ameren Corporation	6.40%	N/A	6.28%	6	4.70%	12	5.79%
5	Avangrid, Inc.	7.40%	N/A	6.77%	3	6.30%	11	6.82%
6	CMS Energy Corporation	6.40%	N/A	6.90%	7	7.18%	18	6.83%
7	Consolidated Edison, Inc.	2.00%	N/A	3.00%	3	3.45%	18	2.82%
8	DTE Energy Company	6.00%	N/A	6.13%	6	4.45%	16	5.53%
9	Duke Energy Corporation	4.90%	N/A	4.58%	6	4.09%	16	4.52%
10	Edison International	5.30%	N/A	5.71%	4	3.90%	16	4.97%
11	Entergy Corporation	7.00%	N/A	3.80%	3	- 1.50%	11	5.40%
12	Eversource Energy	5.60%	N/A	6.08%	6	5.60%	17	5.76%
13	IDACORP, Inc.	3.80%	N/A	3.50%	2	2.50%	3	3.27%
14	MGE Energy, Inc.	N/A	N/A	N/A	N/A	4.00%	N/A	4.00%
15	NextEra Energy, Inc.	8.00%	N/A	7.66%	4	7.99%	17	7.88%
16	OGE Energy Corp.	4.50%	N/A	5.15%	3	3.40%	11	4.35%
17	Otter Tail Corporation	7.00%	N/A	7.40%	1	9.00%	N/A	7.80%
18	Pinnacle West Capital Corporation	6.10%	N/A	5.23%	5	5.05%	15	5.46%
19	PNM Resources, Inc.	5.50%	N/A	6.05%	6	6.22%	10	5.92%
20	Portland General Electric Company	4.60%	N/A	4.53%	4	4.40%	12	4.51%
21	PPL Corporation	N/A	N/A	2.58%	5	0.50%	14	1.54%
22	Public Service Enterprise Group Incorporated	3.20%	N/A	5.01%	3	4.00%	17	4.07%
23	Southern Company	4.50%	N/A	4.52%	6	1.37%	19	3.46%
24	Xcel Energy Inc.	5.40%	N/A	5.43%	5	5.10%	13	5.31%
25	**Average**	**5.55%**	**N/A**	**5.43%**	**4**	**4.80%**	**14**	**5.17%**
26	**Median**							**5.40%**

Sources:
[1] Zacks, http://www.zacks.com/, downloaded on October 4, 2019.
[2] S&P Global Market Intelligence, https://platform.mi.spglobal.com, downloaded on October 4, 2019.
[3] Yahoo! Finance, http://www.finance.yahoo.com/, downloaded on October 4, 2019.

Note:
Yahoo! Finance next year number of estimates.
Negative Growth Rates not included in averages.

DTE Electric Company

Constant Growth DCF Model
(Consensus Analysts' Growth Rates)

Line	Company	13-Week AVG Stock Price[1] (1)	Analysts' Growth[2] (2)	Annualized Dividend[3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	ALLETE, Inc.	$86.11	6.76%	$2.35	2.91%	9.67%
2	Alliant Energy Corporation	$51.53	5.40%	$1.42	2.90%	8.31%
3	American Electric Power Company, Inc.	$90.85	5.87%	$2.68	3.12%	9.00%
4	Ameren Corporation	$76.85	5.79%	$1.90	2.62%	8.41%
5	Avangrid, Inc.	$50.26	6.82%	$1.76	3.74%	10.56%
6	CMS Energy Corporation	$61.04	6.83%	$1.53	2.68%	9.50%
7	Consolidated Edison, Inc.	$88.93	2.82%	$2.96	3.42%	6.24%
8	DTE Energy Company	$129.74	5.53%	$3.78	3.07%	8.60%
9	Duke Energy Corporation	$91.32	4.52%	$3.78	4.33%	8.85%
10	Edison International	$72.26	4.97%	$2.45	3.56%	8.53%
11	Entergy Corporation	$110.09	5.40%	$3.64	3.48%	8.88%
12	Eversource Energy	$79.86	5.76%	$2.14	2.83%	8.59%
13	IDACORP, Inc.	$107.13	3.27%	$2.52	2.43%	5.70%
14	MGE Energy, Inc.	$75.02	4.00%	$1.41	1.95%	5.95%
15	NextEra Energy, Inc.	$217.83	7.88%	$5.00	2.48%	10.36%
16	OGE Energy Corp.	$43.40	4.35%	$1.46	3.51%	7.86%
17	Otter Tail Corporation	$52.30	7.80%	$1.40	2.89%	10.69%
18	Pinnacle West Capital Corporation	$94.23	5.46%	$2.95	3.30%	8.76%
19	PNM Resources, Inc.	$50.47	5.92%	$1.16	2.43%	8.36%
20	Portland General Electric Company	$55.75	4.51%	$1.54	2.89%	7.40%
21	PPL Corporation	$30.19	1.54%	$1.65	5.55%	7.09%
22	Public Service Enterprise Group Incorporated	$59.86	4.07%	$1.88	3.27%	7.34%
23	Southern Company	$58.26	3.46%	$2.48	4.40%	7.87%
24	Xcel Energy Inc.	$62.49	5.31%	$1.62	2.73%	8.04%
25	**Average**	**$78.99**	**5.17%**	**$2.31**	**3.19%**	**8.36%**
26	**Median**					**8.47%**

Sources:
[1] S&P Global Market Intelligence, Downloaded on October 7, 2019.
[2] Exhibit AB-12.
[3] *The Value Line Investment Survey* , July 26, August 16, and September 13, 2019.

DTE Electric Company

Payout Ratios

Line	Company	Dividends Per Share 2018 (1)	Dividends Per Share Projected (2)	Earnings Per Share 2018 (3)	Earnings Per Share Projected (4)	Payout Ratio 2018 (5)	Payout Ratio Projected (6)
1	ALLETE, Inc.	$2.24	$2.85	$3.38	$4.50	66.27%	63.33%
2	Alliant Energy Corporation	$1.34	$1.74	$2.19	$2.80	61.19%	62.14%
3	American Electric Power Company, Inc.	$2.53	$3.40	$3.90	$5.00	64.87%	68.00%
4	Ameren Corporation	$1.85	$2.55	$3.32	$4.25	55.72%	60.00%
5	Avangrid, Inc.	$1.74	$2.10	$1.92	$3.25	90.63%	64.62%
6	CMS Energy Corporation	$1.43	$2.00	$2.32	$3.25	61.64%	61.54%
7	Consolidated Edison, Inc.	$2.86	$3.40	$4.55	$5.00	62.86%	68.00%
8	DTE Energy Company	$3.59	$4.80	$6.17	$7.75	58.18%	61.94%
9	Duke Energy Corporation	$3.64	$4.05	$4.13	$5.75	88.14%	70.43%
10	Edison International	$2.43	$2.70	-$1.26	$5.25	-192.86%	51.43%
11	Entergy Corporation	$3.58	$4.45	$5.88	$6.25	60.88%	71.20%
12	Eversource Energy	$2.02	$2.65	$3.25	$4.25	62.15%	62.35%
13	IDACORP, Inc.	$2.40	$3.20	$4.49	$5.25	53.45%	60.95%
14	MGE Energy, Inc.	$1.32	$1.70	$2.43	$3.25	54.32%	52.31%
15	NextEra Energy, Inc.	$4.44	$7.00	$6.67	$11.50	66.57%	60.87%
16	OGE Energy Corp.	$1.40	$1.90	$2.12	$2.75	66.04%	69.09%
17	Otter Tail Corporation	$1.34	$1.65	$2.06	$2.50	65.05%	66.00%
18	Pinnacle West Capital Corporation	$2.87	$3.80	$4.54	$6.00	63.22%	63.33%
19	PNM Resources, Inc.	$1.09	$1.50	$1.66	$2.50	65.66%	60.00%
20	Portland General Electric Company	$1.43	$1.95	$2.37	$3.00	60.34%	65.00%
21	PPL Corporation	$1.64	$1.80	$2.58	$2.75	63.57%	65.45%
22	Public Service Enterprise Group Incorporated	$1.80	$2.30	$2.76	$4.00	65.22%	57.50%
23	Southern Company	$2.38	$2.78	$3.00	$3.75	79.33%	74.13%
24	Xcel Energy Inc.	$1.52	$2.05	$2.47	$3.25	61.54%	63.08%
25	**Average**	**$2.20**	**$2.85**	**$3.20**	**$4.49**	**54.33%**	**63.45%**

Source:
The Value Line Investment Survey , July 26, August 16, and September 13, 2019.

DTE Electric Company

Sustainable Growth Rate

		3 to 5 Year Projections										Sustainable
Line	**Company**	**Dividends Per Share**	**Earnings Per Share**	**Book Value Per Share**	**Book Value Growth**	**ROE**	**Adjustment Factor**	**Adjusted ROE**	**Payout Ratio**	**Retention Rate**	**Internal Growth Rate**	**Growth Rate**
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	ALLETE, Inc.	$2.85	$4.50	$48.75	3.09%	9.23%	1.02	9.37%	63.33%	36.67%	3.44%	3.54%
2	Alliant Energy Corporation	$1.74	$2.80	$27.55	7.23%	10.16%	1.03	10.52%	62.14%	37.86%	3.98%	5.89%
3	American Electric Power Company, Inc.	$3.40	$5.00	$47.50	4.25%	10.53%	1.02	10.75%	68.00%	32.00%	3.44%	4.77%
4	Ameren Corporation	$2.55	$4.25	$40.75	5.48%	10.43%	1.03	10.71%	60.00%	40.00%	4.28%	5.52%
5	Avangrid, Inc.	$2.10	$3.25	$52.75	1.54%	6.16%	1.01	6.21%	64.62%	35.38%	2.20%	2.20%
6	CMS Energy Corporation	$2.00	$3.25	$24.50	7.86%	13.27%	1.04	13.77%	61.54%	38.46%	5.30%	7.79%
7	Consolidated Edison, Inc.	$3.40	$5.00	$59.75	2.77%	8.37%	1.01	8.48%	68.00%	32.00%	2.71%	3.70%
8	DTE Energy Company	$4.80	$7.75	$73.50	5.49%	10.54%	1.03	10.83%	61.94%	38.06%	4.12%	6.62%
9	Duke Energy Corporation	$4.05	$5.75	$68.75	2.67%	8.36%	1.01	8.47%	70.43%	29.57%	2.51%	2.90%
10	Edison International	$2.70	$5.25	$45.50	7.23%	11.54%	1.03	11.94%	51.43%	48.57%	5.80%	7.97%
11	Entergy Corporation	$4.45	$6.25	$58.00	4.39%	10.78%	1.02	11.01%	71.20%	28.80%	3.17%	6.04%
12	Eversource Energy	$2.65	$4.25	$46.25	4.99%	9.19%	1.02	9.41%	62.35%	37.65%	3.54%	5.96%
13	IDACORP, Inc.	$3.20	$5.25	$56.50	3.75%	9.29%	1.02	9.46%	60.95%	39.05%	3.70%	3.70%
14	MGE Energy, Inc.	$1.70	$3.25	$30.50	5.30%	10.66%	1.03	10.93%	52.31%	47.69%	5.21%	5.21%
15	NextEra Energy, Inc.	$7.00	$11.50	$85.50	3.66%	13.45%	1.02	13.69%	60.87%	39.13%	5.36%	10.03%
16	OGE Energy Corp.	$1.90	$2.75	$23.50	3.22%	11.70%	1.02	11.89%	69.09%	30.91%	3.67%	3.71%
17	Otter Tail Corporation	$1.65	$2.50	$23.25	4.81%	10.75%	1.02	11.01%	66.00%	34.00%	3.74%	5.69%
18	Pinnacle West Capital Corporation	$3.80	$6.00	$56.00	3.75%	10.71%	1.02	10.91%	63.33%	36.67%	4.00%	4.52%
19	PNM Resources, Inc.	$1.50	$2.50	$26.50	4.56%	9.43%	1.02	9.64%	60.00%	40.00%	3.86%	5.66%
20	Portland General Electric Company	$1.95	$3.00	$32.75	3.13%	9.16%	1.02	9.30%	65.00%	35.00%	3.26%	3.42%
21	PPL Corporation	$1.80	$2.75	$21.50	5.85%	12.79%	1.03	13.15%	65.45%	34.55%	4.54%	5.93%
22	Public Service Enterprise Group Incorporated	$2.30	$4.00	$36.00	4.76%	11.11%	1.02	11.37%	57.50%	42.50%	4.83%	4.88%
23	Southern Company	$2.78	$3.75	$30.25	4.81%	12.40%	1.02	12.69%	74.13%	25.87%	3.28%	4.81%
24	Xcel Energy Inc.	$2.05	$3.25	$29.50	4.41%	11.02%	1.02	11.25%	63.08%	36.92%	4.16%	4.84%
25	**Average**	**$2.85**	**$4.49**	**$43.55**	**4.54%**	**10.46%**	**1.02**	**10.70%**	**63.45%**	**36.55%**	**3.92%**	**5.22%**
26	**Median**											**5.04%**

Sources and Notes:
Cols. (1), (2) and (3): *The Value Line Investment Survey* , July 26, August 16, and September 13, 2019.
Col. (4): [Col. (3) / Page 2 Col. (2)] ^ (1/number of years projected) - 1.
Col. (5): Col. (2) / Col. (3).
Col. (6): [2 * (1 + Col. (4))] / (2 + Col. (4)).
Col. (7): Col. (6) * Col. (5).
Col. (8): Col. (1) / Col. (2).
Col. (9): 1 - Col. (8).
Col. (10): Col. (9) * Col. (7).
Col. (11): Col. (10) + Page 2 Col. (9).

DTE Electric Company

Sustainable Growth Rate

Line	Company	13-Week Average Stock Price[1]	2018 Book Value Per Share[2]	Market to Book Ratio	Common Shares Outstanding (in Millions)[2] 2018	3-5 Years	Growth	S Factor[3]	V Factor[4]	S * V
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	ALLETE, Inc.	$86.11	$41.86	2.06	51.50	51.75	0.10%	0.20%	51.39%	0.10%
2	Alliant Energy Corporation	$51.53	$19.43	2.65	236.06	250.00	1.15%	3.06%	62.29%	1.91%
3	American Electric Power Company, Inc.	$90.85	$38.58	2.35	493.25	518.00	0.98%	2.32%	57.54%	1.33%
4	Ameren Corporation	$76.85	$31.21	2.46	244.50	255.00	0.84%	2.08%	59.39%	1.23%
5	Avangrid, Inc.	$50.26	$48.88	1.03	309.01	309.00	- 0.00%	- 0.00%	2.74%	- 0.00%
6	CMS Energy Corporation	$61.04	$16.78	3.64	283.37	297.00	0.94%	3.43%	72.51%	2.49%
7	Consolidated Edison, Inc.	$88.93	$52.11	1.71	321.00	344.00	1.39%	2.38%	41.40%	0.98%
8	DTE Energy Company	$129.74	$56.27	2.31	181.93	200.00	1.91%	4.41%	56.63%	2.50%
9	Duke Energy Corporation	$91.32	$60.27	1.52	727.00	755.00	0.76%	1.15%	34.00%	0.39%
10	Edison International	$72.26	$32.10	2.25	325.81	355.00	1.73%	3.90%	55.58%	2.17%
11	Entergy Corporation	$110.09	$46.78	2.35	189.06	210.00	2.12%	5.00%	57.51%	2.87%
12	Eversource Energy	$79.86	$36.25	2.20	316.89	350.00	2.01%	4.42%	54.61%	2.41%
13	IDACORP, Inc.	$107.13	$47.01	2.28	50.42	50.40	- 0.01%	- 0.02%	56.12%	- 0.01%
14	MGE Energy, Inc.	$75.02	$23.56	3.18	34.67	34.67	0.00%	0.00%	68.60%	0.00%
15	NextEra Energy, Inc.	$217.83	$71.43	3.05	478.00	535.00	2.28%	6.95%	67.21%	4.67%
16	OGE Energy Corp.	$43.40	$20.06	2.16	199.70	200.00	0.03%	0.06%	53.78%	0.03%
17	Otter Tail Corporation	$52.30	$18.38	2.85	39.66	41.80	1.06%	3.01%	64.86%	1.95%
18	Pinnacle West Capital Corporation	$94.23	$46.59	2.02	112.10	115.00	0.51%	1.04%	50.56%	0.52%
19	PNM Resources, Inc.	$50.47	$21.20	2.38	79.65	85.00	1.31%	3.12%	57.99%	1.81%
20	Portland General Electric Company	$55.75	$28.07	1.99	89.27	90.00	0.16%	0.32%	49.65%	0.16%
21	PPL Corporation	$30.19	$16.18	1.87	720.32	780.00	1.60%	2.99%	46.41%	1.39%
22	Public Service Enterprise Group Incorporated	$59.86	$28.53	2.10	504.00	505.00	0.04%	0.08%	52.34%	0.04%
23	Southern Company	$58.26	$23.92	2.44	1,033.80	1,090.00	1.06%	2.59%	58.94%	1.53%
24	Xcel Energy Inc.	$62.49	$23.78	2.63	514.04	525.00	0.42%	1.11%	61.94%	0.69%
25	**Average**	**$78.99**	**$35.38**	**2.31**	**313.96**	**331.11**	**1.02%**	**2.44%**	**53.92%**	**1.42%**

Sources and Notes:
[1] S&P Global Market Intelligence, Downloaded on October 7, 2019.
[2] *The Value Line Investment Survey* , July 26, August 16, and September 13, 2019.
[3] Expected Growth in the Number of Shares, Column (3) * Column (6).
[4] Expected Profit of Stock Investment, [1 - 1 / Column (3)].

DTE Electric Company

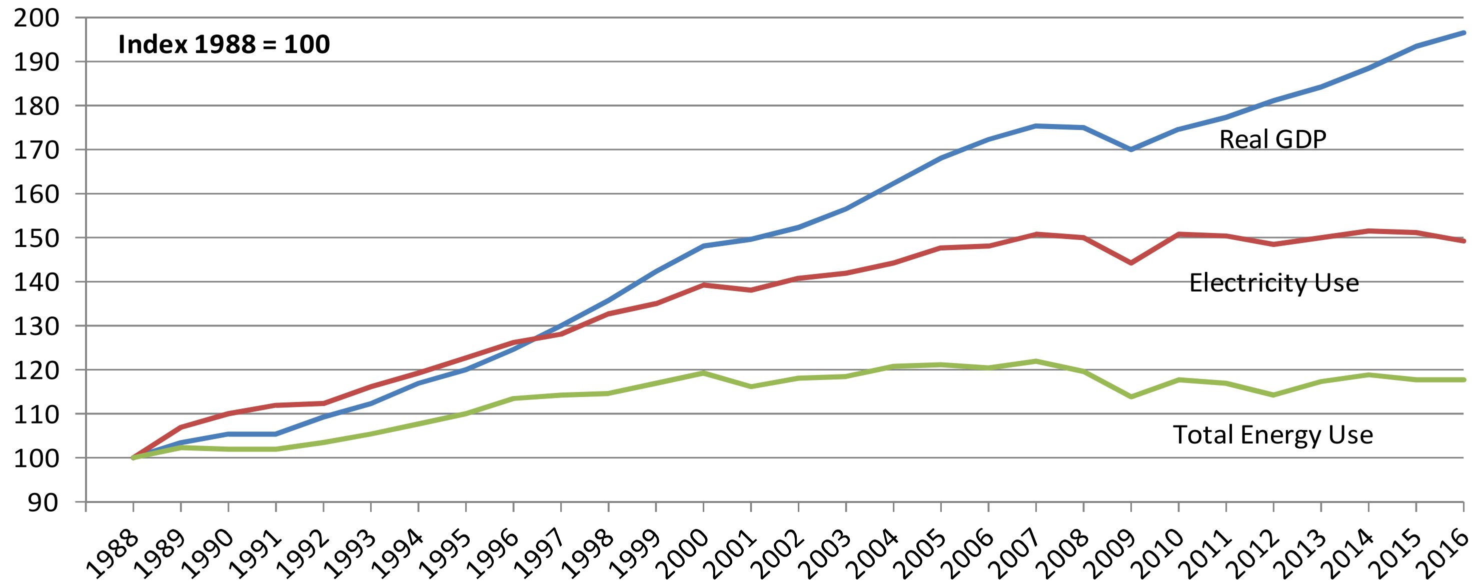
Constant Growth DCF Model
(Sustainable Growth Rate)

Line	Company	13-Week AVG Stock Price[1] (1)	Sustainable Growth[2] (2)	Annualized Dividend[3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	ALLETE, Inc.	$86.11	3.54%	$2.35	2.83%	6.36%
2	Alliant Energy Corporation	$51.53	5.89%	$1.42	2.92%	8.81%
3	American Electric Power Company, Inc.	$90.85	4.77%	$2.68	3.09%	7.86%
4	Ameren Corporation	$76.85	5.52%	$1.90	2.61%	8.13%
5	Avangrid, Inc.	$50.26	2.20%	$1.76	3.58%	5.78%
6	CMS Energy Corporation	$61.04	7.79%	$1.53	2.70%	10.49%
7	Consolidated Edison, Inc.	$88.93	3.70%	$2.96	3.45%	7.15%
8	DTE Energy Company	$129.74	6.62%	$3.78	3.11%	9.72%
9	Duke Energy Corporation	$91.32	2.90%	$3.78	4.26%	7.16%
10	Edison International	$72.26	7.97%	$2.45	3.66%	11.63%
11	Entergy Corporation	$110.09	6.04%	$3.64	3.51%	9.55%
12	Eversource Energy	$79.86	5.96%	$2.14	2.84%	8.80%
13	IDACORP, Inc.	$107.13	3.70%	$2.52	2.44%	6.13%
14	MGE Energy, Inc.	$75.02	5.21%	$1.41	1.98%	7.19%
15	NextEra Energy, Inc.	$217.83	10.03%	$5.00	2.53%	12.55%
16	OGE Energy Corp.	$43.40	3.71%	$1.46	3.49%	7.20%
17	Otter Tail Corporation	$52.30	5.69%	$1.40	2.83%	8.52%
18	Pinnacle West Capital Corporation	$94.23	4.52%	$2.95	3.27%	7.80%
19	PNM Resources, Inc.	$50.47	5.66%	$1.16	2.43%	8.09%
20	Portland General Electric Company	$55.75	3.42%	$1.54	2.86%	6.27%
21	PPL Corporation	$30.19	5.93%	$1.65	5.79%	11.72%
22	Public Service Enterprise Group Incorporated	$59.86	4.88%	$1.88	3.29%	8.17%
23	Southern Company	$58.26	4.81%	$2.48	4.46%	9.27%
24	Xcel Energy Inc.	$62.49	4.84%	$1.62	2.72%	7.56%
25	**Average**	**$78.99**	**5.22%**	**$2.31**	**3.19%**	**8.41%**
26	**Median**					**8.11%**

Sources:
[1] S&P Global Market Intelligence, Downloaded on October 7, 2019.
[2] Exhibit AB-15, page 1.
[3] *The Value Line Investment Survey*, July 26, August 16, and September 13, 2019.

DTE Electric Company

Electricity Sales Are Linked to U.S. Economic Growth



Note:
1988 represents the base year. Graph depicts increases or decreases from the base year.

Sources:
U.S. Energy Information Administration
Federal Reserve Bank of St. Louis

DTE Electric Company

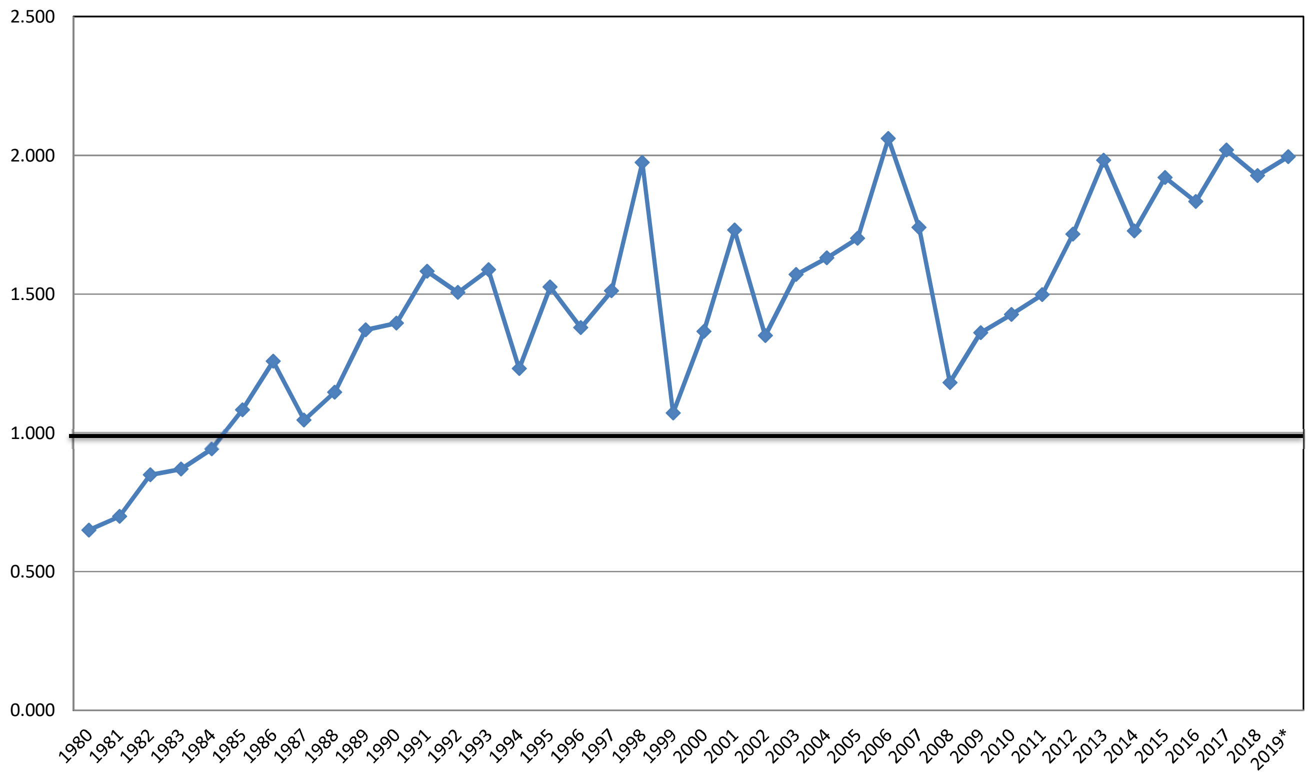
Multi-Stage Growth DCF Model

Line	Company	13-Week AVG Stock Price[1] (1)	Annualized Dividend[2] (2)	First Stage Growth[3] (3)	Second Stage Growth Year 6 (4)	Year 7 (5)	Year 8 (6)	Year 9 (7)	Year 10 (8)	Third Stage Growth[4] (9)	Multi-Stage Growth DCF (10)
1	ALLETE, Inc.	$86.11	$2.35	6.76%	6.31%	5.87%	5.43%	4.99%	4.54%	4.10%	7.46%
2	Alliant Energy Corporation	$51.53	$1.42	5.40%	5.19%	4.97%	4.75%	4.53%	4.32%	4.10%	7.21%
3	American Electric Power Company, Inc.	$90.85	$2.68	5.87%	5.58%	5.28%	4.99%	4.69%	4.40%	4.10%	7.54%
4	Ameren Corporation	$76.85	$1.90	5.79%	5.51%	5.23%	4.95%	4.66%	4.38%	4.10%	6.96%
5	Avangrid, Inc.	$50.26	$1.76	6.82%	6.37%	5.92%	5.46%	5.01%	4.55%	4.10%	8.42%
6	CMS Energy Corporation	$61.04	$1.53	6.83%	6.37%	5.92%	5.46%	5.01%	4.55%	4.10%	7.21%
7	Consolidated Edison, Inc.	$88.93	$2.96	2.82%	3.03%	3.24%	3.46%	3.67%	3.89%	4.10%	7.28%
8	DTE Energy Company	$129.74	$3.78	5.53%	5.29%	5.05%	4.81%	4.58%	4.34%	4.10%	7.42%
9	Duke Energy Corporation	$91.32	$3.78	4.52%	4.45%	4.38%	4.31%	4.24%	4.17%	4.10%	8.52%
10	Edison International	$72.26	$2.45	4.97%	4.83%	4.68%	4.54%	4.39%	4.25%	4.10%	7.83%
11	Entergy Corporation	$110.09	$3.64	5.40%	5.18%	4.97%	4.75%	4.53%	4.32%	4.10%	7.84%
12	Eversource Energy	$79.86	$2.14	5.76%	5.48%	5.21%	4.93%	4.65%	4.38%	4.10%	7.20%
13	IDACORP, Inc.	$107.13	$2.52	3.27%	3.41%	3.54%	3.68%	3.82%	3.96%	4.10%	6.39%
14	MGE Energy, Inc.	$75.02	$1.41	4.00%	4.02%	4.03%	4.05%	4.07%	4.08%	4.10%	5.99%
15	NextEra Energy, Inc.	$217.83	$5.00	7.88%	7.25%	6.62%	5.99%	5.36%	4.73%	4.10%	7.14%
16	OGE Energy Corp.	$43.40	$1.46	4.35%	4.31%	4.27%	4.23%	4.18%	4.14%	4.10%	7.65%
17	Otter Tail Corporation	$52.30	$1.40	7.80%	7.18%	6.57%	5.95%	5.33%	4.72%	4.10%	7.63%
18	Pinnacle West Capital Corporation	$94.23	$2.95	5.46%	5.23%	5.01%	4.78%	4.55%	4.33%	4.10%	7.65%
19	PNM Resources, Inc.	$50.47	$1.16	5.92%	5.62%	5.32%	5.01%	4.71%	4.40%	4.10%	6.78%
20	Portland General Electric Company	$55.75	$1.54	4.51%	4.44%	4.37%	4.31%	4.24%	4.17%	4.10%	7.04%
21	PPL Corporation	$30.19	$1.65	1.54%	1.97%	2.39%	2.82%	3.25%	3.67%	4.10%	8.95%
22	Public Service Enterprise Group Incorporate	$59.86	$1.88	4.07%	4.08%	4.08%	4.09%	4.09%	4.10%	4.10%	7.36%
23	Southern Company	$58.26	$2.48	3.46%	3.57%	3.68%	3.78%	3.89%	3.99%	4.10%	8.36%
24	Xcel Energy Inc.	$62.49	$1.62	5.31%	5.11%	4.91%	4.71%	4.50%	4.30%	4.10%	7.01%
25	**Average**	**$78.99**	**$2.31**	**5.17%**	**4.99%**	**4.81%**	**4.63%**	**4.46%**	**4.28%**	**4.10%**	**7.45%**
26	**Median**										**7.39%**

Sources:
[1] S&P Global Market Intelligence, Downloaded on October 7, 2019.
[2] *The Value Line Investment Survey* , July 26, August 16, and September 13, 2019.
[3] Exhibit AB-12.
[4] *Blue Chip Economic Indicators* , October 10, 2019 at 14.

DTE Electric Company

Common Stock Market/Book Ratio



Source:
1980 - 2000: Mergent Public Utility Manual.
2001 - 2015: AUS Utility Reports, multiple dates.
2016 - 2018: Value Line Investment Survey, multiple dates.
* Value Line Investment Survey Reports, July 26, August 16, August 30, and September 13, 2019.

DTE Electric Company

Equity Risk Premium - Treasury Bond

Line	Year	Authorized Electric Returns[1] (1)	30 yr. Treasury Bond Yield[2] (2)	Indicated Risk Premium (3)	Rolling 5 - Year Average (4)	Rolling 10 - Year Average (5)
1	1986	13.93%	7.80%	6.13%		
2	1987	12.99%	8.58%	4.41%		
3	1988	12.79%	8.96%	3.83%		
4	1989	12.97%	8.45%	4.52%		
5	1990	12.70%	8.61%	4.09%	4.60%	
6	1991	12.55%	8.14%	4.41%	4.25%	
7	1992	12.09%	7.67%	4.42%	4.26%	
8	1993	11.41%	6.60%	4.81%	4.45%	
9	1994	11.34%	7.37%	3.97%	4.34%	
10	1995	11.55%	6.88%	4.67%	4.46%	4.53%
11	1996	11.39%	6.70%	4.69%	4.51%	4.38%
12	1997	11.40%	6.61%	4.79%	4.59%	4.42%
13	1998	11.66%	5.58%	6.08%	4.84%	4.65%
14	1999	10.77%	5.87%	4.90%	5.03%	4.68%
15	2000	11.43%	5.94%	5.49%	5.19%	4.82%
16	2001	11.09%	5.49%	5.60%	5.37%	4.94%
17	2002	11.16%	5.43%	5.73%	5.56%	5.07%
18	2003	10.97%	4.96%	6.01%	5.55%	5.19%
19	2004	10.75%	5.05%	5.70%	5.71%	5.37%
20	2005	10.54%	4.65%	5.89%	5.79%	5.49%
21	2006	10.34%	4.90%	5.44%	5.76%	5.56%
22	2007	10.31%	4.83%	5.48%	5.71%	5.63%
23	2008	10.37%	4.28%	6.09%	5.72%	5.63%
24	2009	10.52%	4.07%	6.45%	5.87%	5.79%
25	2010	10.29%	4.25%	6.04%	5.90%	5.84%
26	2011	10.19%	3.91%	6.28%	6.07%	5.91%
27	2012	10.01%	2.92%	7.09%	6.39%	6.05%
28	2013	9.81%	3.45%	6.36%	6.44%	6.08%
29	2014	9.75%	3.34%	6.41%	6.44%	6.15%
30	2015	9.60%	2.84%	6.76%	6.58%	6.24%
31	2016	9.60%	2.60%	7.00%	6.72%	6.40%
32	2017	9.68%	2.90%	6.79%	6.66%	6.53%
33	2018	9.55%	3.11%	6.44%	6.68%	6.56%
34	2019 [3]	9.57%	2.69%	6.88%	6.77%	6.60%
35	**Average**	**11.03%**	**5.45%**	**5.58%**	**5.54%**	**5.54%**
36	**Minimum**				**4.25%**	**4.38%**
37	**Maximum**				**6.77%**	**6.60%**

Sources:
[1] *Regulatory Research Associates, Inc*., Regulatory Focus, Major Rate Case Decisions, Jan. 1997 pg. 5, and Jan. 2011 pg. 3.
S&P Global Market Intelligence, RRA Regulatory Focus, Major Rate Case Decisions, January- September 2019, October 17, 201
2006 - 2019 Authorized Returns exclude limited issue rider cases.
[2] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.
The yields from 2002 to 2005 represent the 20-Year Treasury yields obtained from the Federal Reserve Bank.
[3] Data includes January - September, 2019.

DTE Electric Company

Equity Risk Premium - Utility Bond

Line	Year	Authorized Electric Returns[1] (1)	Average "A" Rated Utility Bond Yield[2] (2)	Indicated Risk Premium (3)	Rolling 5 - Year Average (4)	Rolling 10 - Year Average (5)
1	1986	13.93%	9.58%	4.35%		
2	1987	12.99%	10.10%	2.89%		
3	1988	12.79%	10.49%	2.30%		
4	1989	12.97%	9.77%	3.20%		
5	1990	12.70%	9.86%	2.84%	3.12%	
6	1991	12.55%	9.36%	3.19%	2.88%	
7	1992	12.09%	8.69%	3.40%	2.99%	
8	1993	11.41%	7.59%	3.82%	3.29%	
9	1994	11.34%	8.31%	3.03%	3.26%	
10	1995	11.55%	7.89%	3.66%	3.42%	3.27%
11	1996	11.39%	7.75%	3.64%	3.51%	3.20%
12	1997	11.40%	7.60%	3.80%	3.59%	3.29%
13	1998	11.66%	7.04%	4.62%	3.75%	3.52%
14	1999	10.77%	7.62%	3.15%	3.77%	3.52%
15	2000	11.43%	8.24%	3.19%	3.68%	3.55%
16	2001	11.09%	7.76%	3.33%	3.62%	3.56%
17	2002	11.16%	7.37%	3.79%	3.61%	3.60%
18	2003	10.97%	6.58%	4.39%	3.57%	3.66%
19	2004	10.75%	6.16%	4.59%	3.86%	3.82%
20	2005	10.54%	5.65%	4.89%	4.20%	3.94%
21	2006	10.34%	6.07%	4.27%	4.39%	4.00%
22	2007	10.31%	6.07%	4.24%	4.48%	4.04%
23	2008	10.37%	6.53%	3.84%	4.37%	3.97%
24	2009	10.52%	6.04%	4.48%	4.34%	4.10%
25	2010	10.29%	5.47%	4.82%	4.33%	4.26%
26	2011	10.19%	5.04%	5.15%	4.51%	4.45%
27	2012	10.01%	4.13%	5.88%	4.83%	4.66%
28	2013	9.81%	4.48%	5.33%	5.13%	4.75%
29	2014	9.75%	4.28%	5.47%	5.33%	4.84%
30	2015	9.60%	4.12%	5.48%	5.46%	4.90%
31	2016	9.60%	3.93%	5.67%	5.57%	5.04%
32	2017	9.68%	4.00%	5.68%	5.53%	5.18%
33	2018	9.55%	4.25%	5.30%	5.52%	5.33%
34	2019 [3]	9.57%	3.89%	5.68%	5.56%	5.45%
35	**Average**	**11.03%**	**6.81%**	**4.22%**	**4.18%**	**4.15%**
36	**Minimum**				**2.88%**	**3.20%**
37	**Maximum**				**5.57%**	**5.45%**

Sources:
[1] *Regulatory Research Associates, Inc*., Regulatory Focus, Major Rate Case Decisions, Jan. 1997 pg. 5, and Jan. 2011 pg. 3.
S&P Global Market Intelligence, RRA Regulatory Focus, Major Rate Case Decisions, January- September 2019, October 17, 2(
2006 - 2019 Authorized Returns exclude limited issue rider cases.
[2] Mergent Public Utility Manual, Mergent Weekly News Reports, 2003.
The utility yields for the period 2001-2009 were obtained from the Mergent Bond Record.
The utility yields from 2010-2019 were obtained from http://credittrends.moodys.com/.
[3] Data includes January - September, 2019.

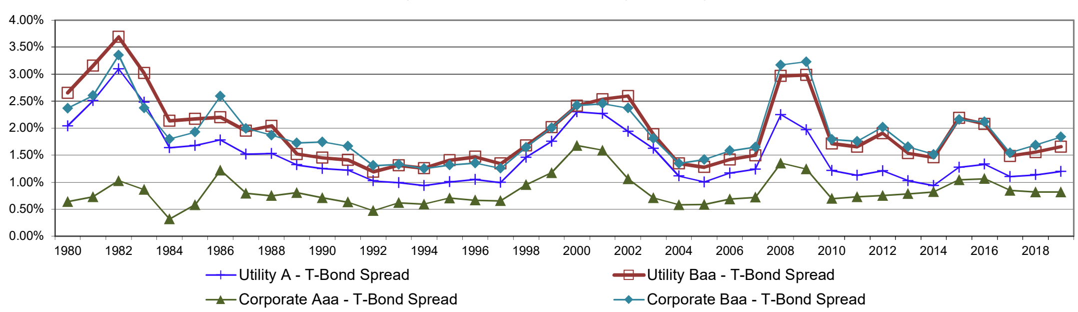
Case No.: U-20561
Exhibit: AB-22
Witness: Christopher C. Walters
Date: November 6, 2019
Page: 1 of 1

DTE Electric Company

Bond Yield Spreads

			Public Utility Bond				Corporate Bond				Utility to Corporate	
		T-Bond			A-T-Bond	Baa-T-Bond			Aaa-T-Bond	Baa-T-Bond	Baa	A-Aaa
Line	Year	Yield[1]	A[2]	Baa[2]	Spread	Spread	Aaa[3]	Baa[3]	Spread	Spread	Spread	Spread
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	1980	11.30%	13.34%	13.95%	2.04%	2.65%	11.94%	13.67%	0.64%	2.37%	0.28%	1.40%
2	1981	13.44%	15.95%	16.60%	2.51%	3.16%	14.17%	16.04%	0.73%	2.60%	0.56%	1.78%
3	1982	12.76%	15.86%	16.45%	3.10%	3.69%	13.79%	16.11%	1.03%	3.35%	0.34%	2.07%
4	1983	11.18%	13.66%	14.20%	2.48%	3.02%	12.04%	13.55%	0.86%	2.38%	0.65%	1.62%
5	1984	12.39%	14.03%	14.53%	1.64%	2.14%	12.71%	14.19%	0.32%	1.80%	0.34%	1.32%
6	1985	10.79%	12.47%	12.96%	1.68%	2.17%	11.37%	12.72%	0.58%	1.93%	0.24%	1.10%
7	1986	7.80%	9.58%	10.00%	1.78%	2.20%	9.02%	10.39%	1.22%	2.59%	-0.39%	0.56%
8	1987	8.58%	10.10%	10.53%	1.52%	1.95%	9.38%	10.58%	0.80%	2.00%	-0.05%	0.72%
9	1988	8.96%	10.49%	11.00%	1.53%	2.04%	9.71%	10.83%	0.75%	1.87%	0.17%	0.78%
10	1989	8.45%	9.77%	9.97%	1.32%	1.52%	9.26%	10.18%	0.81%	1.73%	-0.21%	0.51%
11	1990	8.61%	9.86%	10.06%	1.25%	1.45%	9.32%	10.36%	0.71%	1.75%	-0.30%	0.54%
12	1991	8.14%	9.36%	9.55%	1.22%	1.41%	8.77%	9.80%	0.63%	1.67%	-0.25%	0.59%
13	1992	7.67%	8.69%	8.86%	1.02%	1.19%	8.14%	8.98%	0.47%	1.31%	-0.12%	0.55%
14	1993	6.60%	7.59%	7.91%	0.99%	1.31%	7.22%	7.93%	0.62%	1.33%	-0.02%	0.37%
15	1994	7.37%	8.31%	8.63%	0.94%	1.26%	7.96%	8.62%	0.59%	1.25%	0.01%	0.35%
16	1995	6.88%	7.89%	8.29%	1.01%	1.41%	7.59%	8.20%	0.71%	1.32%	0.09%	0.30%
17	1996	6.70%	7.75%	8.17%	1.05%	1.47%	7.37%	8.05%	0.67%	1.35%	0.12%	0.38%
18	1997	6.61%	7.60%	7.95%	0.99%	1.34%	7.26%	7.86%	0.66%	1.26%	0.09%	0.34%
19	1998	5.58%	7.04%	7.26%	1.46%	1.68%	6.53%	7.22%	0.95%	1.64%	0.04%	0.51%
20	1999	5.87%	7.62%	7.88%	1.75%	2.01%	7.04%	7.87%	1.18%	2.01%	0.01%	0.58%
21	2000	5.94%	8.24%	8.36%	2.30%	2.42%	7.62%	8.36%	1.68%	2.42%	-0.01%	0.62%
22	2001	5.49%	7.76%	8.03%	2.27%	2.54%	7.08%	7.95%	1.59%	2.45%	0.08%	0.68%
23	2002	5.43%	7.37%	8.02%	1.94%	2.59%	6.49%	7.80%	1.06%	2.37%	0.22%	0.88%
24	2003	4.96%	6.58%	6.84%	1.62%	1.89%	5.67%	6.77%	0.71%	1.81%	0.08%	0.91%
25	2004	5.05%	6.16%	6.40%	1.11%	1.35%	5.63%	6.39%	0.58%	1.35%	0.00%	0.53%
26	2005	4.65%	5.65%	5.93%	1.00%	1.28%	5.24%	6.06%	0.59%	1.42%	-0.14%	0.41%
27	2006	4.90%	6.07%	6.32%	1.17%	1.42%	5.59%	6.48%	0.69%	1.58%	-0.16%	0.48%
28	2007	4.83%	6.07%	6.33%	1.24%	1.50%	5.56%	6.48%	0.72%	1.65%	-0.15%	0.52%
29	2008	4.28%	6.53%	7.25%	2.25%	2.97%	5.63%	7.45%	1.35%	3.17%	-0.20%	0.90%
30	2009	4.07%	6.04%	7.06%	1.97%	2.99%	5.31%	7.30%	1.24%	3.23%	-0.24%	0.73%
31	2010	4.25%	5.47%	5.96%	1.22%	1.71%	4.95%	6.04%	0.70%	1.79%	-0.08%	0.52%
32	2011	3.91%	5.04%	5.57%	1.13%	1.66%	4.64%	5.67%	0.73%	1.76%	-0.10%	0.40%
33	2012	2.92%	4.13%	4.83%	1.21%	1.90%	3.67%	4.94%	0.75%	2.02%	-0.11%	0.46%
34	2013	3.45%	4.48%	4.98%	1.03%	1.53%	4.24%	5.10%	0.79%	1.65%	-0.12%	0.24%
35	2014	3.34%	4.28%	4.80%	0.94%	1.46%	4.16%	4.86%	0.82%	1.52%	-0.06%	0.12%
36	2015	2.84%	4.12%	5.03%	1.27%	2.19%	3.89%	5.00%	1.05%	2.16%	0.03%	0.23%
37	2016	2.60%	3.93%	4.67%	1.33%	2.08%	3.66%	4.71%	1.07%	2.12%	-0.04%	0.27%
38	2017	2.90%	4.00%	4.38%	1.10%	1.48%	3.74%	4.44%	0.85%	1.55%	-0.06%	0.26%
39	2018	3.11%	4.25%	4.67%	1.14%	1.56%	3.93%	4.80%	0.82%	1.69%	-0.13%	0.32%
40	2019[4]	2.69%	3.89%	4.35%	1.20%	1.66%	3.51%	4.53%	0.82%	1.84%	-0.18%	0.38%
41	**Average**	**6.43%**	**7.93%**	**8.36%**	**1.49%**	**1.93%**	**7.27%**	**8.36%**	**0.84%**	**1.93%**	**0.01%**	**0.66%**

Yield Spreads
Treasury Vs. Corporate & Treasury Vs. Utility



Sources:
[1] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.
[2] The utility yields for the period 1980-2000 were obtained from Mergent Public Utility Manual, Mergent Weekly News Reports, 2003.
The utility yields for the period 2001-2009 were obtained from the Mergent Bond Record.
The utility yields for the period 2010-2019 were obtained from http://credittrends.moodys.com/.
[3] The corporate yields for the period 1980-2009 were obtained from the St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.
The corporate yields from 2010-2019 were obtained from http://credittrends.moodys.com/.
[4] Data includes January - September, 2019.

DTE Electric Company

Treasury and Utility Bond Yields

Line	Date	Treasury Bond Yield[1] (1)	"A" Rated Utility Bond Yield[2] (2)	"Baa" Rated Utility Bond Yield[2] (3)
1	10/04/19	2.01%	3.26%	3.60%
2	09/27/19	2.13%	3.35%	3.68%
3	09/20/19	2.17%	3.41%	3.75%
4	09/13/19	2.37%	3.57%	3.92%
5	09/06/19	2.02%	3.24%	3.58%
6	08/30/19	1.96%	3.19%	3.53%
7	08/23/19	2.02%	3.23%	3.56%
8	08/16/19	2.01%	3.23%	3.55%
9	08/09/19	2.26%	3.38%	3.71%
10	08/02/19	2.39%	3.47%	3.81%
11	07/26/19	2.59%	3.68%	4.01%
12	07/19/19	2.57%	3.69%	4.18%
13	07/12/19	2.64%	3.76%	4.24%
14	**Average**	**2.24%**	**3.42%**	**3.78%**
15	**Spread To Treasury**		**1.18%**	**1.54%**

Sources:
[1] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org.
[2] http://credittrends.moodys.com/.

DTE Electric Company

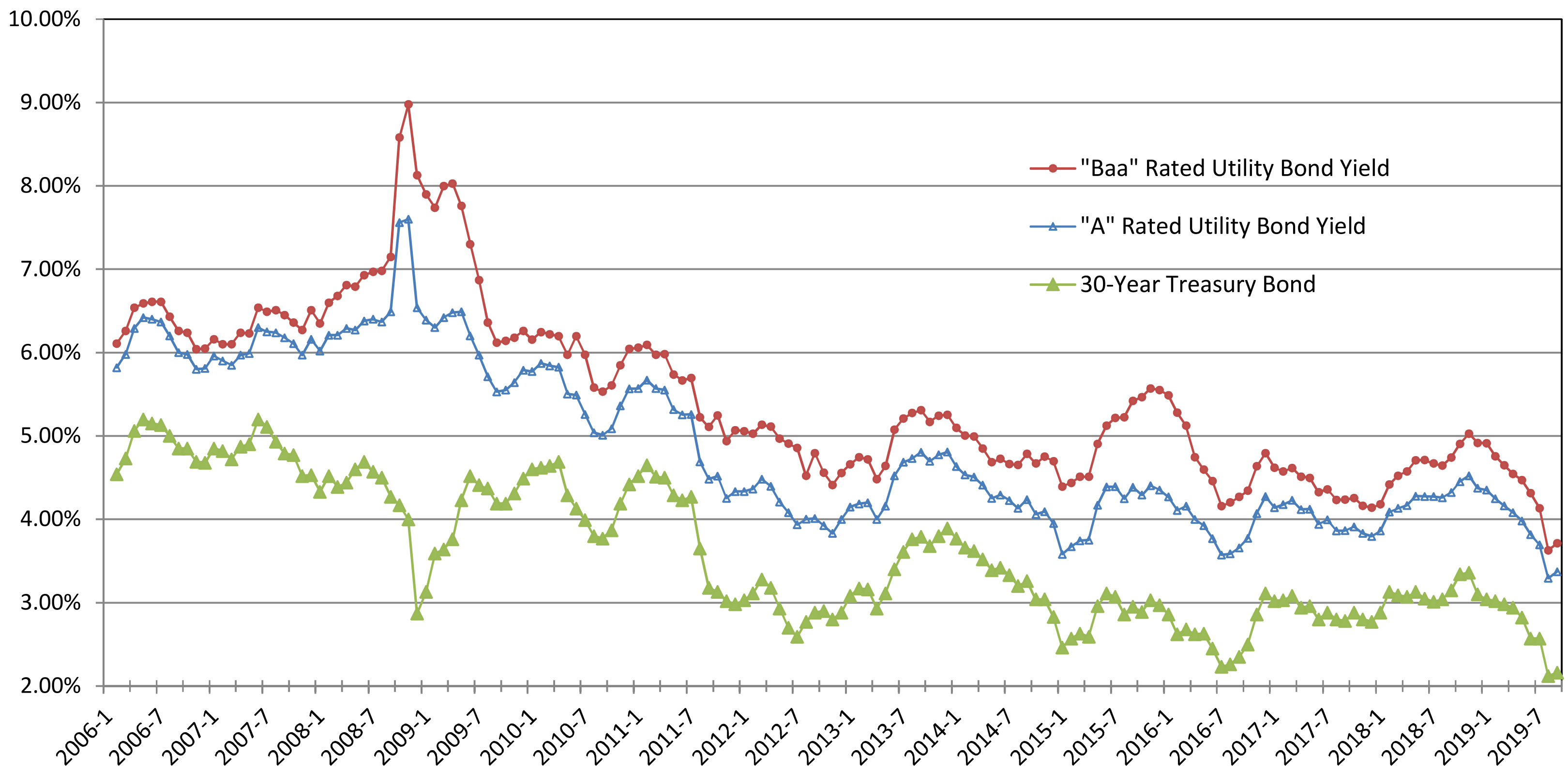
Treasury and Utility Bond Yields

Line	Date	Treasury Bond Yield[1] (1)	"A" Rated Utility Bond Yield[2] (2)	"Baa" Rated Utility Bond Yield[2] (3)
1	10/04/19	2.01%	3.26%	3.60%
2	09/27/19	2.13%	3.35%	3.68%
3	09/20/19	2.17%	3.41%	3.75%
4	09/13/19	2.37%	3.57%	3.92%
5	09/06/19	2.02%	3.24%	3.58%
6	08/30/19	1.96%	3.19%	3.53%
7	08/23/19	2.02%	3.23%	3.56%
8	08/16/19	2.01%	3.23%	3.55%
9	08/09/19	2.26%	3.38%	3.71%
10	08/02/19	2.39%	3.47%	3.81%
11	07/26/19	2.59%	3.68%	4.01%
12	07/19/19	2.57%	3.69%	4.18%
13	07/12/19	2.64%	3.76%	4.24%
14	07/05/19	2.54%	3.72%	4.19%
15	06/28/19	2.52%	3.72%	4.19%
16	06/21/19	2.59%	3.80%	4.30%
17	06/14/19	2.59%	3.86%	4.36%
18	06/07/19	2.57%	3.84%	4.35%
19	05/31/19	2.58%	3.83%	4.33%
20	05/24/19	2.75%	3.95%	4.47%
21	05/17/19	2.82%	3.99%	4.48%
22	05/10/19	2.89%	4.01%	4.51%
23	05/03/19	2.93%	4.05%	4.50%
24	04/26/19	2.92%	4.04%	4.49%
25	04/18/19	2.96%	4.08%	4.55%
26	04/12/19	2.97%	4.11%	4.57%
27	**Average**	**2.49%**	**3.67%**	**4.09%**
28	**Spread To Treasury**		**1.18%**	**1.60%**

Sources:
[1] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org.
[2] http://credittrends.moodys.com/.

DTE Electric Company

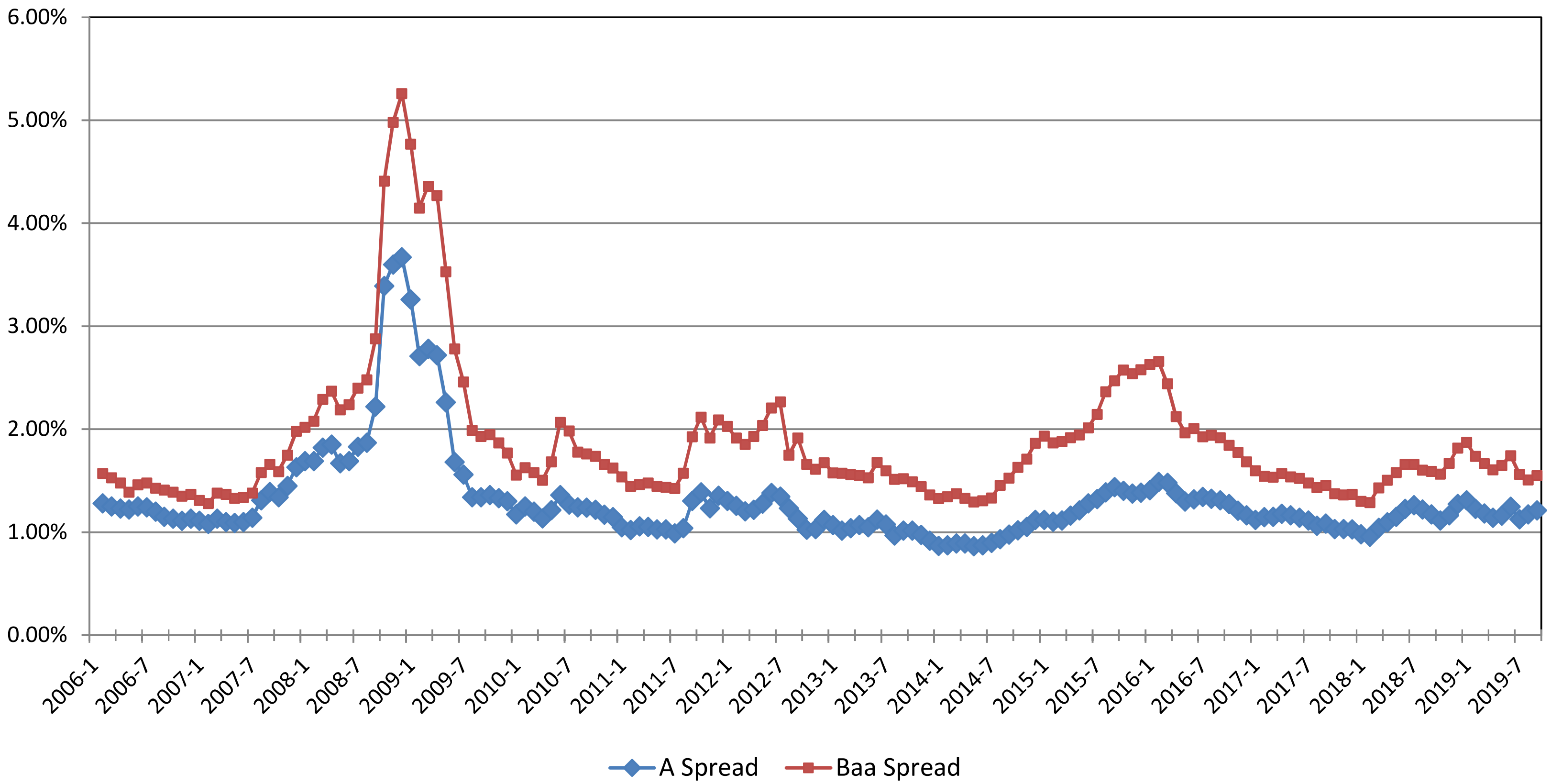
Trends in Bond Yields



Sources:
Mergent Bond Record.
www.moodys.com, Bond Yields and Key Indicators.
St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/

DTE Electric Company

Yield Spread Between Utility Bonds and 30-Year Treasury Bonds



Sources:
Mergent Bond Record.
www.moodys.com, Bond Yields and Key Indicators.
St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/

DTE Electric Company

Value Line Beta

Line	Company	Beta
1	ALLETE, Inc.	0.65
2	Alliant Energy Corporation	0.60
3	American Electric Power Company, Inc.	0.55
4	Ameren Corporation	0.55
5	Avangrid, Inc.	0.40
6	CMS Energy Corporation	0.55
7	Consolidated Edison, Inc.	0.45
8	DTE Energy Company	0.55
9	Duke Energy Corporation	0.50
10	Edison International	0.60
11	Entergy Corporation	0.60
12	Eversource Energy	0.60
13	IDACORP, Inc.	0.60
14	MGE Energy, Inc.	0.55
15	NextEra Energy, Inc.	0.55
16	OGE Energy Corp.	0.80
17	Otter Tail Corporation	0.65
18	Pinnacle West Capital Corporation	0.55
19	PNM Resources, Inc.	0.60
20	Portland General Electric Company	0.60
21	PPL Corporation	0.65
22	Public Service Enterprise Group Incorporated	0.65
23	Southern Company	0.50
24	Xcel Energy Inc.	0.50
25	**Average**	**0.58**
26	**Median**	**0.58**
27	**Historical Beta**[2]	**0.68**

Source:
[1] *The Value Line Investment Survey,*
July 26, August 16, and September 13, 2019.
[2] Exhibit AB-24, page 2.

DTE Electric Company

Historical Betas
(Electric Utilities)

Line	Company	Average	2Q19	1Q19	4Q18	3Q18	2Q18	1Q18	4Q17	3Q17	2Q17	1Q17	4Q16	3Q16	2Q16	1Q16	4Q15	3Q15	2Q15	1Q15	4Q14	3Q14
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)
1	ALLETE, Inc.	0.76	0.65	0.65	0.65	0.70	0.75	0.75	0.80	0.75	0.80	0.80	0.75	0.75	0.75	0.80	0.80	0.80	0.80	0.80	0.80	0.80
2	Alliant Energy Corporation	0.73	0.60	0.65	0.60	0.65	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.75	0.75	0.80	0.80	0.80	0.80	0.80	0.80	0.80
3	American Electric Power Company, Inc.	0.65	0.55	0.55	0.55	0.60	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
4	Ameren Corporation	0.69	0.60	0.60	0.55	0.60	0.65	0.65	0.70	0.65	0.65	0.70	0.65	0.70	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
5	Avangrid, Inc.	0.36	0.40	0.40	0.30	0.30	0.40	0.35	NMF	NMF	NMF	NMF	NMF	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	CMS Energy Corporation	0.66	0.55	0.55	0.55	0.55	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.70	0.75	0.75	0.70	0.75	0.75	0.70	0.75
7	Consolidated Edison, Inc.	0.53	0.45	0.45	0.45	0.45	0.50	0.50	0.50	0.50	0.50	0.55	0.55	0.55	0.55	0.55	0.60	0.60	0.60	0.60	0.60	0.60
8	DTE Energy Company	0.67	0.55	0.55	0.55	0.60	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.70	0.70	0.75	0.75	0.75	0.75	0.75	0.75	0.75
9	Duke Energy Corporation	0.58	0.50	0.50	0.55	0.55	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.65	0.50	0.60	0.60	0.60	0.60	0.60
10	Edison International	0.67	0.60	0.55	0.60	0.60	0.60	0.65	0.65	0.60	0.60	0.65	0.65	0.70	0.70	0.70	0.70	0.75	0.75	0.75	0.75	0.75
11	Entergy Corporation	0.66	0.60	0.60	0.60	0.60	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.70	0.70	0.70	0.65	0.70	0.70	0.70	0.70
12	Eversource Energy	0.69	0.60	0.60	0.60	0.60	0.65	0.65	0.65	0.65	0.65	0.70	0.70	0.70	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
13	IDACORP, Inc.	0.73	0.60	0.55	0.60	0.65	0.70	0.70	0.70	0.70	0.75	0.75	0.75	0.75	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
14	MGE Energy, Inc.	0.70	0.55	0.60	0.60	0.65	0.70	0.70	0.75	0.75	0.75	0.70	0.70	0.70	0.70	0.70	0.75	0.75	0.75	0.70	0.70	0.70
15	NextEra Energy, Inc.	0.67	0.60	0.60	0.60	0.60	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.70	0.70	0.75	0.70	0.75	0.70	0.70	0.70
16	OGE Energy Corp.	0.91	0.80	0.85	0.85	0.90	0.95	0.95	0.95	0.95	0.95	0.95	0.90	0.90	0.95	0.95	0.95	0.90	0.90	0.90	0.90	0.85
17	Otter Tail Corporation	0.85	0.70	0.70	0.75	0.80	0.85	0.85	0.90	0.90	0.90	0.85	0.85	0.85	0.80	0.85	0.85	0.85	0.90	0.90	0.90	0.95
18	Pinnacle West Capital Corporation	0.68	0.55	0.55	0.60	0.65	0.65	0.70	0.70	0.65	0.70	0.70	0.70	0.70	0.75	0.75	0.75	0.70	0.70	0.70	0.70	0.70
19	PNM Resources, Inc.	0.77	0.65	0.65	0.60	0.75	0.70	0.75	0.75	0.75	0.70	0.75	0.75	0.80	0.80	0.80	0.85	0.85	0.85	0.85	0.85	0.85
20	Portland General Electric Company	0.72	0.60	0.60	0.60	0.65	0.65	0.70	0.70	0.70	0.70	0.70	0.70	0.75	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.75
21	PPL Corporation	0.69	0.70	0.70	0.70	0.70	0.75	0.75	0.75	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.65	0.65	0.65	0.60	0.65
22	Public Service Enterprise Group Incorpora	0.71	0.65	0.65	0.65	0.65	0.70	0.70	0.70	0.70	0.65	0.70	0.70	0.70	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
23	Southern Company	0.56	0.50	0.50	0.50	0.50	0.55	0.65	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.60	0.60	0.55	0.60	0.55	0.55	0.60
24	Xcel Energy Inc.	0.61	0.50	0.50	0.55	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.70	0.65
25	**Average**	0.68	0.59	0.59	0.59	0.62	0.66	0.67	0.69	0.68	0.68	0.69	0.68	0.70	0.72	0.74	0.74	0.73	0.74	0.73	0.73	0.73

Source: Value Line Software Analyzer

DTE Electric Company

Electric CAPM Return

Line	Description	Risk Premium[2] Derived MRP (1)	FERC 2-Step DCF[3] Derived MRP (2)
	Current Beta		
1	Risk-Free Rate[1]	2.50%	2.50%
2	Market Risk Premium	8.50%	8.60%
3	Beta[4]	0.58	0.58
4	**CAPM**	**7.39%**	**7.45%**
	Historical Beta		
5	Risk-Free Rate[1]	2.50%	2.50%
6	Market Risk Premium	8.50%	8.60%
7	Historical Beta[4]	0.68	0.68
8	**CAPM**	**8.24%**	**8.31%**

Sources:
[1] *Blue Chip Financial Forecasts*, October 1, 2019, at 2.
[2] *Duff & Phelps, 2019 SBBI Yearbook* at 6-18.
[3] *State Street Global Advisors, downloaded 9/9/2019.*
[4] Exhibit AB-24, page 1.

DTE Electric Company

Development of the Market Risk Premium

Line	Description	MRP	
	Risk Premium Based Method:		
1	Lg. Co. Stock Real Market Return	8.80%	[1]
2	Projected Consumer Price Index	2.00%	[2]
3	Expected Market Return	10.98%	
4	Risk Free Rate	2.50%	[2]
5	Market Risk Premium	**8.50%**	
	FERC 2-Step DCF Based Method:		
6	Short-Term S&P 500 Growth	11.34%	[3]
7	Long-Term GDP Growth	4.10%	[4]
8	Blended Growth Rate	8.93%	[5]
9	Index Dividend Yield	2.01%	[3]
10	Adjusted Yield	2.19%	
11	Expected Market Return	11.12%	
12	Risk Free Rate	2.50%	[2]
13	Market Risk Premium	**8.60%**	

Sources & Note:

[1] Duff & Phelps 2019 SBBI Yearbook at 6-18.

[2] Blue Chip Financial Forecasts, October 1, 2019.

[3] State Street Global Advisors, downloaded 10/7/2019.

[4] Blue Chip Economic Indicators, October 10, 2019.

[5] (2/3*11.34%) + (1/3*4.10%) = 8.93%.

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-1.5]
Respondent:	B. Villadsen
Page:	1 of 1

Question: Please confirm the overall cost of capital methodology described by Dr. Villadsen in her Appendix B, and employed on her Schedules D5.8 D5.12 is the same as the ATWACC methodology previously employed by Dr. Vilbert in DTE's previous electric and gas rate cases. If it is not the same, please explain the differences.

Answer: Confirmed.

Attachments: *None*

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-4.34]
Respondent:	T. M. Uzenski
Page:	1 of 1

Question: Referring to the above question, please provide a calculation of the incremental increase in depreciation expense for Belle River in the projected test year as a result of the depreciation rates approved in Case No. U-18150. Please provide the calculation in Microsoft Excel with all formulas intact.

Answer: Please see attached.

Attachments: U-20561 ABDE 4.34 Belle River Depreciation Estimate.xls

Michigan Public Service Commission
DTE Electric Company
Projected Depreciation - Estimated for Belle River only
Projected 12 Month Period Ending Apr. 30, 2021
($000)

Case No.: U-20561
Discovery Request: ABDE-4.34
Data of Request: October 8, 2019
Witness: T. M. Uzenski

Line No.	(a) Description	(b) Historical Plant Balance 12/31/18	(c) U-16117 Depr. Rate	(d) Calculated Depreciation at 12/31/18	(e) U-18150 Depr. Rate	(f) Calculated Depreciation at 12/31/18	(g) Increase in Belle River Composite Rate
				(b) x (c)		*(b) x (e)*	*(e) - (c)*
1	Depreciable Plant - Belle River:						
2	311-Structures & Imprv - Belle River Common	138,312,395	1.61%	2,226,830	3.31%	4,578,140	
3	312-Boiler Plant Equip - Belle River Common	190,129,544	1.58%	3,004,047	3.33%	6,331,314	
4	314-Turbogenerator Units - Belle River Common	62,961,703	1.49%	938,129	3.15%	1,983,294	
5	315-Accessory Elect Equip - Belle River Common	9,721,597	1.51%	146,796	2.90%	281,926	
6	316-Misc Power Plant Eqp - Belle River Common	4,182,736	1.58%	66,087	3.31%	138,449	
7	311-Structures & Imprv - Belle River Unit 1	108,677,570	1.48%	1,608,428	2.91%	3,162,517	
8	312-Boiler Plant Equip - Belle River Unit 1	444,669,627	1.59%	7,070,247	3.66%	16,274,908	
9	314-Turbogenerator Units - Belle River Unit 1	87,700,177	1.64%	1,438,283	3.50%	3,069,506	
10	315-Accessory Elect Equip - Belle River Unit 1	16,276,362	1.73%	281,581	3.51%	571,300	
11	316-Misc Power Plant Eqp - Belle River Unit 1	981,419	1.58%	15,506	2.86%	28,069	
12	311-Structures & Imprv - Belle River Unit 2	112,164,934	1.47%	1,648,825	2.89%	3,241,567	
13	312-Boiler Plant Equip - Belle River Unit 2	457,921,560	1.61%	7,372,537	3.70%	16,943,098	
14	314-Turbogenerator Units - Belle River Unit 2	105,616,480	1.53%	1,615,932	3.11%	3,284,673	
15	315-Accessory Elect Equip - Belle River Unit 2	11,953,757	1.61%	192,455	3.05%	364,590	
16	316-Misc Power Plant Eqp - Belle River Unit 2	1,221,800	1.58%	19,304	2.86%	34,943	
17	Total Depreciable Plant	1,752,491,661		27,644,988		60,288,293	
18	Composite Depreciation Rate - Belle River only			1.58%		3.44%	1.86%

Line No.	Description	Amount	Source
19	Depreciable Plant Bal. at 12/31/2018	1,752,491,661	
20	Capital Exp. 16 Months Ended April 2020	60,931,000	Exh. A-12 B5.1 p. 3 (line 3, col. e)
21	Depreciable Plant Bal. at 4/30/2020	1,813,422,661	
22	Capital Exp. 12 Months Ended April 2021	42,539,000	Exh. A-12 B5.1 p. 3 (line 3, col. f)
23	Depreciable Plant Bal. at 4/30/2021	1,855,961,661	
24	Average Projected Balance	1,834,692,161	Average Line 21 and Line 23
25	Increase in Composite Depreciation Rate - Belle River only	1.86%	Carried from Column (g) above
26	Increase in Projected Depreciation - Estimated for Belle River only	34,174,437	Line 24 x Line 25

DTE Electric Company

Regulatory Plan
($000)

		Company Proposed				Adjusted			
Line	Description	Protected Plant (1)	Unprotected Plant (2)	Non-Plant (3)	Total (4)	Protected Plant (5)	Unprotected Plant (6)	Non-Plant (7)	Total (8)
1	Amortization Period (years)	ARAM	23	14		ARAM	13	9	
2	Tax Reform Liability Before Gross Up	$ (613,051)	$ (621,506)	$ (126,015)	$ (1,360,572)	$ (613,051)	$ (621,506)	$ (126,015)	$ (1,360,572)
	Amortization Schedule								
3	2019	$ (11,040)	$ (17,452)	$ (5,813)	$ (34,305)	$ (11,040)	$ (17,452)	$ (5,813)	$ (34,305)
4	2020	(23,589)	(27,022)	(9,001)	(59,612)	(23,589)	(47,808)	(14,002)	(85,399)
5	2021	(24,957)	(27,022)	(9,001)	(60,980)	(24,957)	(47,808)	(14,002)	(86,767)
6	2022	(21,593)	(27,022)	(9,001)	(57,616)	(21,593)	(47,808)	(14,002)	(83,403)
7	2023	(23,112)	(27,022)	(9,001)	(59,135)	(23,112)	(47,808)	(14,002)	(84,922)
8	2024	(25,014)	(27,022)	(9,001)	(61,037)	(25,014)	(47,808)	(14,002)	(86,824)
9	2025	(23,132)	(27,022)	(9,001)	(59,155)	(23,132)	(47,808)	(14,002)	(84,942)
10	2026	(21,878)	(27,022)	(9,001)	(57,901)	(21,878)	(47,808)	(14,002)	(83,688)
11	2027	(19,777)	(27,022)	(9,001)	(55,800)	(19,777)	(47,808)	(14,002)	(81,587)
12	2028	(17,697)	(27,022)	(9,001)	(53,720)	(17,697)	(47,808)	(8,189)	(73,693)
13	2029	(18,396)	(27,022)	(9,001)	(54,419)	(18,396)	(47,808)	-	(66,204)
14	Amortization beyond 2029	(382,866)	(333,834)	(30,191)	(746,892)	(382,866)	(125,973)	-	(508,839)
15	Total Amortization	$ (613,051)	$ (621,506)	$ (126,015)	$ (1,360,572)	$ (613,051)	$ (621,506)	$ (126,015)	$ (1,360,572)
16	Test Year Amortization[1]	$ (24,045)	$ (27,022)	$ (9,001)	$ (60,068)	$ (24,045)	$ (47,808)	$ (14,002)	$ (85,855)
17	Revenue Conversion Factor[2]				1.3496				1.3496
18	**Revenue Requirement Impact**				**$ (81,068)**				**$ (115,870)**
19	**Difference**								**$ (34,802)**

Sources:
Exhibit A-13 Schedule C8.1.
[1] Exhibit A-13, Schedule C8, Line 54.
[2] Exhibit A-11, Schedule A1, Line 7.

DTE Electric Company

Regulatory Plan
Capital Structure Impact

Line	Description	Capital Structure: Amounts ($000) (1)	Capital Structure: Percent Permanent Capital (2)	Capital Structure: Percent of Total Capital (3)	Cost Rate % (4)	Weighted Costs: Permanent Capital (5)	Weighted Costs: Total Cost % (6)	Weighted Costs: Conversion Factor (7)	Weighted Costs: Pre-Tax Return (8)
	DTE Proposed[1]								
1	Long-Term Debt	6,995,149	50.00%	38.33%	4.31%	2.16%	1.65%	1.0000	1.65%
2	Preferred Stock	0	0.00%	0.00%	0.00%	0.00%	0.00%	1.3496	0.00%
3	Common Shareholders' Equity	6,993,099	50.00%	38.32%	10.50%	5.25%	4.02%	1.3496	5.43%
4	Total	13,988,248	100.00%			7.41%			
5	Short-Term Debt	219,881		1.20%	3.25%		0.04%	1.0000	0.04%
6	Investment Tax Credit (ITC) - Debt	24,309		0.13%	4.31%		0.01%	1.0000	0.01%
7	Investment Tax Credit (ITC) - Equity	24,309		0.13%	10.50%		0.01%	1.3496	0.02%
8	Total Investment Tax Credit (ITC)	48,618							
9	Deferred Income Taxes (Net)	3,994,582		21.89%	0.00%		0.00%		0.00%
10	Total	18,251,329		100.00%			5.73%		7.15%
	Adjusted[2]								
11	Long-Term Debt	7,008,042	50.00%	38.40%	4.31%	2.16%	1.66%	1.0000	1.66%
12	Preferred Stock	0	0.00%	0.00%	0.00%	0.00%	0.00%	1.3496	0.00%
13	Common Shareholders' Equity	7,005,993	50.00%	38.39%	10.50%	5.25%	4.03%	1.3496	5.44%
14	Total	14,014,035	100.00%			7.41%			
15	Short-Term Debt	219,881		1.20%	3.25%		0.04%	1.0000	0.04%
16	Investment Tax Credit (ITC) - Debt	24,309		0.13%	4.31%		0.01%	1.0000	0.01%
17	Investment Tax Credit (ITC) - Equity	24,309		0.13%	10.50%		0.01%	1.3496	0.02%
18	Total Investment Tax Credit (ITC)	48,618							
19	Deferred Income Taxes (Net)	3,968,795		21.75%	0.00%		0.00%		0.00%
20	Total	18,251,329		100.00%			5.74%		7.16%
21	Difference						0.01%		0.01%
22	**Rate Base**								**18,251,329**
23	**Revenue Requirement Impact**								**2,409**

Source and Note:
[1] Exhibit A-14, Schedule D1.
[2] Long-Term Debt and Common Equity were increased equally to offset the reduction in Deferred Income Taxes.

DTE Electric Company

Regulatory Plan
NPV of Revenue Requirement

Line	Description	2019 (1)	2020 (2)	2021 (3)	2022 (4)	2023 (5)	2024 (6)	2025 (7)	2026 (8)	2027 (9)	2028 (10)	2029 (11)	2030 (12)
	Regulatory Plan												
1	Unprotected Non-Plant Amort	$ (7,846)	$ (16,647)	$ (18,897)	$ (18,897)	$ (18,897)	$ (18,897)	$ (18,897)	$ (18,897)	$ (18,897)	$ (11,051)	$ -	$ -
2	Unprotected Plant Amort	(23,553)	(55,171)	(64,522)	(64,522)	(64,522)	(64,522)	(64,522)	(64,522)	(64,522)	(64,522)	(64,522)	(64,522)
3	Incremental Increase in ROR+Taxes	-	1,606	4,818	7,228	9,637	12,046	14,455	16,864	19,273	21,683	24,092	26,501
4	BR Incremental Depreciation Expense	34,174	34,174	34,174	34,174	34,174	34,174	34,174	34,174	34,174	34,174	34,174	34,174
5	Net Revenue Requirement	$ 2,776	$ (36,037)	$ (44,426)	$ (42,017)	$ (39,607)	$ (37,198)	$ (34,789)	$ (32,380)	$ (29,971)	$ (19,716)	$ (6,256)	$ (3,847)
6	Discount Rate	5.74%											
7	**NPV of Revenue Requirement**	**($236,344)**											
	As Proposed by DTE												
8	Unprotected Non-Plant Amort	$ (7,846)	$ (12,148)	$ (12,148)	$ (12,148)	$ (12,148)	$ (12,148)	$ (12,148)	$ (12,148)	$ (12,148)	$ (12,148)	$ (12,148)	$ (12,148)
9	Unprotected Plant Amort	(23,553)	(36,469)	(36,469)	(36,469)	(36,469)	(36,469)	(36,469)	(36,469)	(36,469)	(36,469)	(36,469)	(36,469)
10	Increase in ROR+Taxes	-	-	-	-	-	-	-	-	-	-	-	-
11	BR Incremental Depreciation Expense	34,174	34,174	34,174	34,174	34,174	34,174	34,174	34,174	34,174	34,174	34,174	34,174
12	Net Revenue Requirement	$ 2,776	$ (14,442)	$ (14,442)	$ (14,442)	$ (14,442)	$ (14,442)	$ (14,442)	$ (14,442)	$ (14,442)	$ (14,442)	$ (14,442)	$ (14,442)
13	Discount Rate	5.73%											
14	**NPV of Revenue Requirement**	**($106,584)**											
15	**Difference in NPV of Rev. Req.**	**($129,759)**											

Cost of Service Study
0-0-100
Production Costs

		(a) Total Electric	(b) Total Residential	(c) Total Commercial Secondary	(d) Total Primary	(e) E-1 St Lgt D9 OPL E-2 Signals
1	Rate Base	10,054,008	3,729,793	2,450,591	3,817,833	55,791
2	Revenue	3,147,456	1,319,188	760,175	1,056,454	11,640
3	Expenses:					
4	Fuel	1,069,602	433,114	267,347	363,900	5,241
5	Purchased Power	315,387	116,091	67,526	130,734	1,035
6	O & M Expense	704,412	290,013	173,005	238,460	2,934
7	Depreciation	434,332	159,016	105,711	167,127	2,478
8	Other (Reg Assets, etc)	0	0	0	0	0
9	Remove Reg Assets	0	0	0	0	0
10	Accretion of Loss/ Gain on Sale	0	0	0	0	0
11	Other Taxes	146,612	55,136	35,735	54,956	785
12	Income Taxes	49,616	27,643	11,528	10,532	(87)
13	Amortizations	-	-	-	-	-
14	Total Expenses	2,719,959	1,081,013	660,851	965,709	12,386
15	Net Oper Income	427,497	238,175	99,324	90,745	(747)
16	AFUDC & Other	25,909	9,486	6,306	9,969	148
17	Net Adjustments	488	181	119	185	3
18	Adj Net Oper Income	453,894	247,842	105,749	100,899	(596)
19	Rate of Return	4.51%	6.74%	4.32%	2.64%	-1.07%
20	Return @ 5.7338 %	576,477	213,859	140,512	218,907	3,199
21	Income Deficiency	122,583	(33,983)	34,763	118,008	3,795
22	Base Revenue Def / (Sufficiency)	165,442	(45,865)	46,917	159,268	5,122
23	Additional Rev Req	0	-	-	-	-
24	Total Revenue Def/ (Sufficiency)	165,442	(45,865)	46,917	159,268	5,122
25	Revenue Requirement	3,312,898	1,273,323	807,092	1,215,722	16,762
26	Misc Revenue	35,246	26,131	5,023	4,036	56
27	Rev Req Excl Misc Rev & Nuc Decomm	3,277,653	1,247,192	802,069	1,211,686	16,706

Cost of Service Study
0-0-100
Production Costs

		(f) D-1/Other Residential Service	(g) D-1.2 TOU -	(h) D-2 Residential Space Ht	(i) Total Residential	(j) D-3/Other General Service	(k) D-3.2 Secondary Schools	(l) D-4 Lg Genl Service	(m) Total Commercial Secondary
1	Rate Base	3,617,503	38,709	73,581	3,729,793	1,848,151	61,681	540,758	2,450,591
2	Revenue	1,286,167	12,130	20,891	1,319,188	583,673	17,177	159,325	760,175
3	Expenses:								
4	Fuel	421,017	4,155	7,942	433,114	203,226	6,394	57,727	267,347
5	Purchased Power	113,247	998	1,847	116,091	51,623	1,579	14,324	67,526
6	O & M Expense	282,581	2,594	4,838	290,013	131,872	4,113	37,020	173,005
7	Depreciation	154,141	1,674	3,200	159,016	79,610	2,682	23,419	105,711
8	Other (Reg Assets, etc)	0	0	0	0	0	0	0	0
8	Other (Reg Assets, etc)	0	0	0	0	0	0	0	0
10	Accretion of Loss/ Gain on Sale	0	0	0	0	0	0	0	0
11	Other Taxes	53,512	561	1,063	55,136	26,990	892	7,852	35,735
12	Income Taxes	27,211	223	208	27,643	9,396	158	1,974	11,528
13	Amortizations	-	-	-	-	-	-	-	-
14	Total Expenses	1,051,709	10,205	19,098	1,081,013	502,717	15,819	142,315	660,851
15	Net Oper Income	234,457	1,925	1,793	238,175	80,956	1,359	17,009	99,324
16	AFUDC & Other	9,195	100	191	9,486	4,749	160	1,397	6,306
17	Net Adjustments	176	2	4	181	90	3	26	119
18	Adj Net Oper Income	243,829	2,027	1,987	247,842	85,795	1,522	18,433	105,749
19	Rate of Return	6.74%	5.24%	2.70%	6.64%	4.64%	2.47%	3.41%	4.32%
20	Return @ 5.7338 %	207,420	2,220	4,219	213,859	105,969	3,537	31,006	140,512
21	Income Deficiency	(36,408)	193	2,232	(33,983)	20,175	2,015	12,573	34,763
22	Base Revenue Def / (Sufficiency)	(49,138)	260	3,012	(45,865)	27,228	2,720	16,969	46,917
23	Additional Rev Req	-	-	-	-	-	-	-	-
24	Total Revenue Def/ (Sufficiency)	(49,138)	260	3,012	(45,865)	27,228	2,720	16,969	46,917
25	Revenue Requirement	1,237,029	12,390	23,903	1,273,323	610,901	19,897	176,294	807,092
26	Misc Revenue	25,594	139	398	26,131	4,241	85	697	5,023
27	Rev Req Excl Misc Rev & Nuc Decomm	1,211,435	12,252	23,506	1,247,192	606,660	19,811	175,597	802,069

Cost of Service Study
0-0-100
Production Costs

		(n) D-11/Other Primary	(o) D-6.2 Primary Schools	(p) D-8 Interrupt Supply	(q) R-1.1/R-1.2 Metal Melt Process Heat	(r) R-10 Interrupt Supply	(s) Total Primary
1	Rate Base	3,041,403	91,348	166,013	131,359	387,710	3,817,833
2	Revenue	863,321	30,010	41,164	31,206	90,752	1,056,454
3	Expenses:						
4	Fuel	309,896	10,069	16,929	13,307	13,699	363,900
5	Purchased Power	74,974	2,606	3,571	2,683	46,899	130,734
6	O & M Expense	196,533	6,624	9,721	7,409	18,172	238,460
7	Depreciation	132,351	3,923	7,297	5,792	17,764	167,127
8	Other (Reg Assets, etc)	0	0	0	0	0	0
8	Other (Reg Assets, etc)	0	0	0	0	0	0
10	Accretion of Loss/ Gain on Sale	0	0	0	0	0	0
11	Other Taxes	43,858	1,338	2,364	1,863	5,534	54,956
12	Income Taxes	10,993	567	133	16	(1,177)	10,532
13	Amortizations	-	-	-	-	-	-
14	Total Expenses	768,605	25,127	40,016	31,070	100,891	965,709
15	Net Oper Income	94,716	4,883	1,148	136	(10,139)	90,745
16	AFUDC & Other	7,895	234	435	345	1,059	9,969
17	Net Adjustments	148	4	8	6	19	185
18	Adj Net Oper Income	102,759	5,122	1,591	488	(9,061)	10,154
19	Rate of Return	3.38%	5.61%	0.96%	0.37%	-2.34%	0.27%
20	Return @ 5.7338 %	174,388	5,238	9,519	7,532	22,231	218,907
21	Income Deficiency	71,629	116	7,928	7,044	31,291	118,008
22	Base Revenue Def / (Sufficiency)	96,673	156	10,699	9,507	42,232	159,268
23	Additional Rev Req	-	-	-	-	-	-
24	Total Revenue Def/ (Sufficiency)	96,673	156	10,699	9,507	42,232	159,268
25	Revenue Requirement	959,995	30,167	51,863	40,713	132,984	1,215,722
26	Misc Revenue	3,286	114	160	121	355	4,036
27	Rev Req Excl Misc Rev & Nuc Decomm	956,709	30,053	51,703	40,592	132,629	1,211,686

Cost of Service Study
0-0-100
Production Costs

		-	(t)	(u)	(v)	(w)
		-				
		- Alloc	D-9 OPL Residential	D-9 OPL Commercial	E-1 St Lght	E-2 Signals
1	Rate Base		1,561	5,892	34,528	13,810
2	Revenue		327	1,076	6,734	3,503
3	Expenses:					
4	Fuel		146	553	3,186	1,356
5	Purchased Power		27	101	588	319
6	O & M Expense		77	293	1,712	852
7	Depreciation		70	263	1,540	605
8	Other (Reg Assets, etc)	900	0	0	0	0
8	Other (Reg Assets, etc)	900	0	0	0	0
10	Accretion of Loss/ Gain on Sale	900	0	0	0	0
11	Other Taxes		22	82	483	198
12	Income Taxes		(1)	(22)	(81)	18
13	Amortizations		-	-	-	-
14	Total Expenses		340	1,270	7,429	3,348
15	Net Oper Income		(12)	(193)	(696)	155
16	AFUDC & Other		4	16	92	36
17	Net Adjustments		0	0	2	1
18	Adj Net Oper Income		(8)	(177)	(602)	192
19	Rate of Return		-0.52%	-3.01%	-1.74%	1.39%
20	Return @ 5.7338 %		90	338	1,980	792
21	Income Deficiency		98	515	2,582	600
22	Base Revenue Def / (Sufficiency)		132	695	3,484	810
23	Additional Rev Req		-	-	-	-
24	Total Revenue Def/ (Sufficiency)		132	695	3,484	810
25	Revenue Requirement		459	1,772	10,218	4,313
26	Misc Revenue		1	4	36	13
27	Rev Req Excl Misc Rev & Nuc Decomm		458	1,767	10,182	4,299

Ten Year Hourly Base Load Analysis - DTE Electric

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Average
Total (kWh)	46,447,384,336	45,821,507,107	38,202,882,677	43,305,609,948	43,413,974,168	42,567,827,179	42,523,412,652	43,088,686,853	41,814,692,125	43,495,828,374	43,068,180,542
Max (kWh)	9,341,634	9,648,310	8,821,732	10,247,417	9,667,136	9,052,855	8,763,673	9,341,694	8,805,517	9,408,303	9,309,827
Min (kWh)	3,512,071	3,405,301	2,878,339	3,201,779	3,214,006	3,227,738	3,155,583	3,218,795	2,974,629	3,218,329	3,200,657
Min % of Max	37.6%	35.3%	32.6%	31.2%	33.2%	35.7%	36.0%	34.5%	33.8%	34.2%	**34.4%**

Source: DTE's response to ABATE Data Request No. ABDE-3.27 (DTE's Part III Filing, Attachment 5 (28))

Baseload Generator Cost Analysis

Plant Function	Plant Name	Total Cost
Base	Monroe	$4,012,614,884
Base	Belle River DTE	$1,812,272,332
Base	Fermi 2	$1,396,110,064
Base	St. Clair PP	$1,019,027,247
Base	Greenwood EC	$402,515,736
Base	Trenton Channel PP	$381,601,139
Base	River Rouge	$256,701,856
Total Base		**$9,280,843,258**
Other	Dean Peaker	$143,141,900
Other	Renaissance Peaker	$127,656,215
Other	Belle River Gas Peaker	$87,269,003
Other	Greenwood Peaker	$78,059,417
Other	Delray Peaker	$58,552,294
Other	Northeast Peaker	$19,597,218
Other	Hancock Peaker	$18,490,427
Other	Enrico Fermi Peaker	$11,085,855
Other	Superior Peaker	$8,220,774
Other	St. Clair Peaker	$4,857,821
Other	Belle River Oil Peaker	$3,732,243
Other	Placid Peaker	$2,245,114
Other	Putnam Peaker	$2,234,600
Other	Oliver Peaker	$2,223,626
Other	Colfax Peaker	$2,153,169
Other	Monroe Peaker	$2,111,450
Other	Wilmont Peaker	$2,060,040
Other	Slocum Peaker	$1,793,604
Other	River Rouge Peaker	$1,661,405
Total Other		**$577,146,175**
Pumped Storage	**Ludington**	**$466,574,431**
Wind-Solar	SCIO Solar Array	$1,056,389
Wind-Solar	Blue Cross Blue Shield Solar	$1,280,365
Wind-Solar	Monroe County Community Solar	$1,416,415
Wind-Solar	Ford Solar Array	$2,415,913
Wind-Solar	Training and Development Center Solar	$1,883,542
Wind-Solar	General Motors Solar Arraqy	$2,854,803
Wind-Solar	DTE Headquarters	$943,978
Wind-Solar	Mercy High School	$2,253,796
Wind-Solar	Warren Consolidated Schools	$1,358,581
Wind-Solar	General Motoros Orion Assembly	$1,639,547
Wind-Solar	Huron Clinton Indian Springs Metro	$1,926,723
Wind-Solar	Wil-Le Farms	$2,023,310

Baseload Generator Cost Analysis

Plant Function	Plant Name	Total Cost
Wind-Solar	Immaculate House of Mary	$2,138,538
Wind-Solar	University of Michigan - North Campus Center	$2,364,767
Wind-Solar	University of Michigan - Institute of Science	$1,946,758
Wind-Solar	Riopelle Farms	$2,415,665
Wind-Solar	St. Clair RESA	$2,736,445
Wind-Solar	Leipprandt Orchards	$2,520,176
Wind-Solar	Hartland Schools	$2,206,626
Wind-Solar	McPhail	$3,807,828
Wind-Solar	Dominos Farm	$5,869,747
Wind-Solar	Thumb Electric Cooperative	$3,950,470
Wind-Solar	Ford World Headquarters	$5,605,365
Wind-Solar	Ashley	$2,826,877
Wind-Solar	Brownstown	$2,001,531
Wind-Solar	Greenwood Energy Center	$4,829,017
Wind-Solar	Ypsilanti	$3,159,802
Wind-Solar	General Motors - Warren	$2,602,203
Wind-Solar	Demille	$60,304,889
Wind-Solar	Turrill	$40,915,768
Wind-Solar	O'Shea	$5,804,948
Wind-Solar	Gratiot Wind Park	$249,398,309
Wind-Solar	Thumb Wind Park (Minden)	$79,601,601
Wind-Solar	Thumb Wind Park (Sigel)	$150,564,258
Wind-Solar	Thumb Wind Park (McKinley)	$37,506,800
Wind-Solar	Echo Wind Park	$373,606,489
Wind-Solar	Brookfield Wind Park	$166,806,172
Total Wind-Solar		**$1,236,544,411**
Total All Production		**$11,561,108,275**

Total Base Load Cost	$9,280,843,258
Total Cost of all Generating Units	$11,561,108,275
Base Load Cost as a Percent of Total Cost	80.3%
2018 Base Load as percent of Max Load (from Exhibit AB-30)	34.2%
Percent to be Allocated on Energy	27.5%

Source: DTE Electric 2018 FERC Form 1

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-3.27]
Respondent:	A. M. Brasil
Page:	1 of 1

Question: Please provide 10 years of hourly load data by rate schedule for the 10-year period ending 12/31/2018. Please provide this information in Microsoft Excel format. Note similar information was previously provided in U-18255 in response to Staff Audit Data Request NMR-6.3.

Answer: Please see DTE's Part III filing, Attachment 5(28).

Attachments: N/A

MPSC Case No.:	U-20561
Requestor:	DTE Electric Co
Question No.:	DEMECNRDCSC-2.1
Respondent:	Douglas Jester
Page:	1 of 2

Question: DEMECNRDCSC-2.1

Please refer to page 3, lines 15 through 18, of Mr. Boothman's direct testimony:

a Please identify each electric utility that currently uses (as of September 6, 2019) the Equivalent Peaker Method, as defined in the National Association of Regulatory Utility Commissioners (NARUC) Electric Utility Cost Allocation Manual (January, 1992), for production cost allocation within its approved cost of service study.

b For each utility listed in response to question DEMECNRDCSC-2.1a above, please provide the date, case number and a copy of the applicable utility commission order approving use of the Equivalent Peaker Method, as defined in the National Association of Regulatory Utility Commissioners (NARUC) Electric Utility Cost Allocation Manual (January, 1992), for production cost allocation.

Answer:

We have not exhaustively surveyed the cost of service study practices of the various states and utilities. We are aware that Equivalent Peaker Methods are used in the states of Minnesota, North Dakota, and South Dakota under the label "plant stratification" and in the states of Washington and Idaho under the label "peak credit".

To our knowledge, the most recent final order in which the Minnesota Public Utilities Commission addresses the allocation of production plant costs is its order of June 12, 2017 in docket E-002/GR-15—826, at pages 38-40. The utility in that case was Northern States Power Company d/b/a Xcel Energy.

To our knowledge, the most recent case in which the South Dakota Public Utilities Commission addresses the allocation of production plant costs is docket EL14-058. See Exhibit JPG-1, Schedule 2 filed by Xcel Energy in that docket on June 23, 2014.

To our knowledge, the most recent case in which the North Dakota Public Utilities Commission addresses the allocation of production plant costs is docket NDPU-12-813. See Exhibit MAP-1 in that docket, filed by Northern State Power Company (Xcel) on December 18, 2012.

To our knowledge, the most recent case in which the Washington Utilities and Transportation Commission addressed the allocation of production plant costs is docket UE-170033, see attached order dated December 5, 2017. The utility in that case was Puget Sound Energy.

To our knowledge, the most recent case in Idaho in which the Idaho Public Utilities Commission addressed the allocation of production plant costs is docket AVU-E-19-04. See testimony filed on November 1, 2019 by Joseph Miller for Avista Utilities Corporation supporting stipulation and settlement in that case.

MPSC Case No.:	U-20561
Requestor:	DTE Electric Co
Question No.:	DEMECNRDCSC-2.1
Respondent:	Douglas Jester
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Attachments:

- Minnesota PUC Order (15-826)
- S. Dakota Docket EL14-058 JPG-1 Schedule 2
- N. Dakota Docket NDPU-12-813 MAP-1
- Washington EU-170033 and UG-170034 – Final Order 08
- Idaho PUC 2019-11-01 MILLER DIRECT (AVU-E-19-04)

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie J. Sieben	Commissioner
John A. Tuma	Commissioner

In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota

ISSUE DATE: June 12, 2017

DOCKET NO. E-002/GR-15-826

FINDINGS OF FACT, CONCLUSIONS, AND ORDER

Contents

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PROCEDURAL HISTORY

I. Initial Filings and Orders

On November 2, 2015, Northern States Power Company d/b/a Xcel Energy (Xcel, or the Company) filed this general rate case seeking three consecutive annual rate increases under the Multiyear Rate Plan statute.[1] The proposed rate increases would total $297,100,000, or 9.8% over current rates, and would be phased in as follows:

1. a 2016 increase of $194,600,000, or 6.4% over current rates;
2. a 2017 increase of $52,100,000, an additional 1.7% over current rates; and
3. a 2018 increase of $50,400,000, an additional 1.7% over current rates.

The filing included a proposed interim-rate schedule. On the same date, the Company filed a petition to establish a new base cost of energy for the period during which interim rates would be in effect; that petition was granted by order dated December 22, 2015.[2]

Also on December 22, 2015, the Commission issued three orders in this case:

- an order finding the rate-case filing substantially complete and suspending the proposed final rates;
- a notice and order for hearing referring the case to the Office of Administrative Hearings for contested-case proceedings; and

[1] Minn. Stat. § 216B.16, subd. 19.

[2] *In the Matter of the Application of Northern States Power Company for Approval of a New Base Cost of Energy*, Docket No. E-002/15-827, Order Setting New Base Cost of Energy (December 22, 2015).

- an order setting interim rates for the period during which the rate case was being resolved.

II. The Parties and Their Representatives

The following parties appeared in this case:[3]

- Northern States Power Company, represented by Eric F. Swanson, David M. Aafedt, and Joseph M. Windler, Winthrop and Weinstine, P.A.; Elizabeth M. Brama, Briggs and Morgan, P.A.; and Amanda Rome and Ryan J. Long, Assistant General Counsels with Xcel Energy Services, Inc.
- Minnesota Department of Commerce, Division of Energy Resources (the Department), represented by Julia E. Anderson, Linda S. Jensen, and Peter Madsen, Assistant Attorneys General.
- Office of the Minnesota Attorney General–Residential Utilities and Antitrust Division (OAG), represented by Ryan Barlow, Ian Dobson, Joseph Meyer, and Joseph Dammel, Assistant Attorneys General.
- Minnesota Chamber of Commerce (the Chamber), represented by Richard J. Savelkoul, Martin & Squires, P.A.
- Fresh Energy, Sierra Club, Wind on the Wires, Minnesota Center for Environmental Advocacy (MCEA), and Natural Resources Defense Council, (NRDC) (together, the Clean Energy Organizations) represented by Hudson Kingston, attorney with the MCEA, and Samantha Williams, attorney with the NRDC.
- An ad hoc association of large commercial customers, including JC Penney Corporation, Inc., Macy's, Inc., Sam's West, Inc. and Wal-Mart Stores, Inc. (together, the Commercial Group), represented by Alan R. Jenkins, Jenkins at Law, LLC.
- Suburban Rate Authority, represented by James M. Strommen and Adam C. Wattenbarger, Kennedy & Graven, Chartered.
- City of Minneapolis, represented by Corey Conover, Minneapolis Assistant City Attorney.
- CHS Inc.; Flint Hills Resources, LP; Gerdau Ameristeel US Inc.; USG Interiors, Inc.; and Unimin Corporation (together, Xcel Large Industrials, or XLI), represented by Andrew P. Moratzka, Sarah Johnson Phillips, and Emma J. Fazio, Stoel Rives, L.L.P.
- U.S. Energy Services and an ad hoc group of industrial, commercial, and institutional customers (together, ICI Group), represented by Peder A. Larson and Inga K. Schuchard, Larkin, Hoffman, Daly & Lindgren, Ltd.
- Energy CENTS Coalition (ECC), represented by Pam Marshall, Executive Director.
- AARP, represented by John Coffman, Attorney at Law.

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[3] The ALJ granted (with limitations) the Energy Freedom Coalition of America's petition to intervene in the case, but the organization later withdrew.

III. Proceedings Before the Administrative Law Judge

The Office of Administrative Hearings assigned Administrative Law Judge (ALJ) Jeffery Oxley to hear the case.

The parties filed direct, rebuttal, and surrebuttal testimony prior to the opening of evidentiary hearings. The ALJ held an evidentiary hearing in Saint Paul October 25 – 27, 2016. After the hearings the parties filed initial briefs, reply briefs, and proposed findings of fact and conclusions of law.

The ALJ also held eight public hearings in the case, on the dates and at the locations set forth below:

- July 12, 2016 – Merriam Park Public Library, St. Paul – 1:00 p.m.
- July 12, 2016 – Earle Brown Heritage Center, Minneapolis – 7:00 p.m.
- July 13, 2016 – Intergovernmental Center, Mankato – 7:00 p.m.
- July 19, 2016 – Wilder Complex, Minneapolis – 1:00 p.m.
- July 19, 2016 – Woodbury Central Park, Woodbury – 7:00 p.m.
- July 20, 2016 – City Hall, Eden Prairie – 7:00 p.m.
- July 26, 2016 – Lake George Municipal Complex, St. Cloud – 7:00 p.m.
- July 27, 2016 – Southeast Technical College, Red Wing – 7:00 p.m.

In May 2016, the Chief ALJ appointed a mediator, ALJ Jeanne M. Cochran, at the request of Xcel. The mediator conducted a mediation over three days in July 2016. The mediation resulted in a partial settlement among most, but not all, parties.

In August 2016, the Company filed a Stipulation of Settlement (the Settlement) entered into by nine of twelve parties to this case (the Settling Parties). The Settling Parties stated that they were able to resolve, between them: (1) all revenue requirements issues, (2) issues related to a medical needs customer bill-payment-assistance program, and (3) issues related to street lighting.

The Settlement was not joined by the OAG, AARP, or the Clean Energy Organizations, and it was opposed in part by the OAG and AARP. The ALJ recommended that the Commission adopt the settlement.

IV. Public Comments

The Administrative Law Judge held eight public hearings, where the Company, the Department, the OAG, and the Commission's staff were available to make presentations and field questions from members of the public.

All public comments are filed in the case record. Written comments are labeled "Public Comment," of which the Commission and the ALJ received over 487. In addition, over 40 individuals provided oral comments at the public hearings. Comments generally, though not universally, opposed Xcel's request for a rate increase. Other concerns raised in public comments included matters of conservation and renewable or sustainable energy, nuclear power generation, distributed generation, pollution from an Xcel-operated trash incinerator in Red Wing, employee (including executive) compensation, fuel costs, and service quality.

A more comprehensive summary of public comments considered by the ALJ and the Commission can be found in Attachment A to the Administrative Law Judge's Findings of Fact, Conclusions of Law, and Recommendations.

V. Proceedings Before the Commission

On March 1, 2017, the Administrative Law Judge filed his Findings of Fact, Conclusions of Law, and Recommendations (the ALJ's Report). The following parties filed exceptions to the ALJ's Report under Minn. Stat. § 14.61 and Minn. R. 7829.2700: the Company, the Department, the OAG, XLI, the Chamber, the Commercial Group, and the Clean Energy Organizations.

On May 4 and 11, 2017, the Commission heard oral argument from and asked questions of the parties. On May 11, 2017, the record closed under Minn. Stat. § 14.61, subd. 2.

Having examined the entire record in this case, and having heard the arguments of the parties, the Commission makes the following findings, conclusions, and order.

FINDINGS AND CONCLUSIONS

I. The Ratemaking Process

A. The Substantive Legal Standard

The legal standard for utility rate changes is that the new rates must be just and reasonable.[4] The Minnesota Supreme Court has described the Commission's statutory mandate for determining whether proposed rates are just and reasonable as "broadly defined in terms of balancing the interests of the utility companies, their shareholders, and their customers," citing Minn. Stat. § 216B.16, subd. 6.[5] That statute is set forth in pertinent part below:

> The commission, in the exercise of its powers under this chapter to determine just and reasonable rates for public utilities, shall give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, and to earn a fair and reasonable return upon the investment in such property.

B. The Commission's Role

While the Public Utilities Act provides baseline guidance on the ratemaking treatment of different kinds of utility costs, it generally makes only threshold determinations on rate recoverability, leaving to the Commission the tasks of determining (a) the accuracy and validity

[4] Minn. Stat. § 216B.16, subds. 4, 5, and 6.

[5] *In re Interstate Power Co.*, 574 N.W.2d 408, 411 (Minn. 1998).

of claimed costs; (b) the prudence and reasonableness of claimed costs; and (c) the compatibility of claimed costs with the public interest.

In ratemaking, therefore, the Commission must decide a wide range of issues, from the accuracy of the financial information provided by the utility, to the prudence and reasonableness of the underlying transactions and business judgments, to the proper distribution of the final revenue requirement among different customer classes.

These diverse issues require different analytical approaches, involve different burdens of proof, and require the Commission to exercise different functions and powers. In ratemaking the Commission acts in both quasi-judicial and quasi-legislative capacities: As a quasi-judicial body it engages in traditional fact-finding, and as a quasi-legislative body it applies its institutional expertise and judgment to resolve issues that turn on both factual findings and policy judgments. As the Supreme Court has explained,

> [I]n the exercise of the statutorily imposed duty to determine whether the inclusion of the item generating the claimed cost is appropriate, or whether the ratepayers or the shareholders should sustain the burden generated by the claimed cost, the MPUC acts in both a quasi-judicial and a partially legislative capacity. To state it differently, in evaluating the case, the accent is more on the inferences and conclusions to be drawn from the basic facts (i.e., the amount of the claimed costs) rather than on the reliability of the facts themselves. Thus, by merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of demonstrating it is just and reasonable that the ratepayers bear the costs of those expenses.[6]

C. The Burden of Proof

Under the Public Utilities Act, utilities seeking a rate increase have the burden of proof to show that the proposed rate change is just and reasonable.[7] Any doubt as to reasonableness is to be resolved in favor of the consumer.[8]

On purely factual issues, the Commission acts in its quasi-judicial capacity and weighs evidence in the same manner as a district court, requiring that facts be proved by a preponderance of the evidence. On issues involving policy judgments, the Commission acts in its quasi-legislative capacity, balancing competing interests and policy goals to arrive at the resolution most consistent with the broad public interest.

Utilities seeking rate changes must therefore prove not only that the facts they present are accurate, but that the costs they seek to recover are rate-recoverable, that the rate recovery mechanisms they propose are permissible, and that the rate design they advocate is equitable, under the "just and reasonable" standard set by statute. As the Court of Appeals explained, quoting the Supreme Court,

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[6] *In re N. States Power Co.*, 416 N.W.2d 719, 722–23 (Minn. 1987) (citation omitted).

[7] Minn. Stat. § 216B.16, subd. 4.

[8] Minn. Stat. § 216B.03.

> A utility seeking to change its rates has the burden of proving by a preponderance of the evidence that its proposed rate change is just and reasonable. Minn. Stat. § 216B.16, subd. 4 (1986). "Preponderance of the evidence" is defined for ratemaking proceedings as "whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility when considered together with the Commission's statutory responsibility to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates."[9]

D. Multiyear Rate Plan Statute

Minn. Stat. § 216B.16, subd. 19, authorizes the Commission to approve multiyear rate plans. A multiyear rate plan establishes the rates a utility may charge for each year of a specified period of years (not to exceed five years), based only on the utility's reasonable and prudent costs of service over the term of the plan. The statute does not alter the ordinary requirement that the Commission find that the plan results in just and reasonable rates, or that the burden of proof is on the utility proposing the plan.

The statute also authorizes the Commission to establish the terms, conditions, and procedures for such plans, which it did by order on June 17, 2013.[10] The Commission established that utilities may propose a multiyear rate plan to improve the regulatory process for recovery of (a) costs related to specific, clearly identified capital projects, and (b) appropriate non-capital costs.[11]

II. Summary of the Issues

Many initially contested issues were resolved among several of the parties in the course of evidentiary proceedings. The Administrative Law Judge found that the resolutions reached by the parties were reasonable and supported by record evidence; he recommended accepting them.[12]

Other issues remained contested, and some issues resolved among the settling parties were disputed by one or more non-settling parties. The following issues either were contested or otherwise require discussion.

<u>Financial and Cost-of-Capital Issues</u>

- ***Stipulation of Settlement*—**Should the Commission approve the partial settlement, and if so, should the settlement be modified to address issues resolved by the settlement but disputed by nonsettling parties, including performance metrics, nuclear refueling outage

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[9] *In re Minn. Power & Light Co.*, 435 N.W.2d 550, 554 (Minn. App. 1989) (citation omitted).

[10] *In the Matter of the Minnesota Office of the Attorney General–Antitrust and Utilities Division's Petition for a Commission Investigation Regarding Criteria and Standards for Multiyear Rate Plans Under Minn. Stat. § 216B.16, subd. 19*, Docket No. E,G-999/M-12-587, Order Establishing Terms, Conditions, and Procedures for Multiyear Rate Plans (June 17, 2013) (the Multiyear Rate Plan Order).

[11] Multiyear Rate Plan Order at 12.

[12] ALJ's Report ¶ 685.

accounting, interest on the interim rate refund, and the accuracy of Xcel's capital spending budgets?

Class-Cost-of-Service-Study (CCOSS) Issues

- ***Classification of Fixed Plant*—**Should Xcel classify generation plant as demand-related and allocate those costs to each customer class based on the class's share of peak demand?
- ***Classification of D10S Allocator*—**Should Xcel calculate its D10S Allocator based on its own system peak, MISO's peak, or by some other method?
- ***Usage of Peak Demand and Energy Losses*—**Should Xcel be required to account for energy losses as part of its CCOSS?
- ***Calculation of Renewable Development Fund Rider Cost Allocation*—**Should Xcel be required to allocate Renewable Development Fund Rider costs as 50% energy and 50% demand?

Rate-Design Issues

- ***Interclass Revenue Apportionment*—**What is a fair and reasonable apportionment of responsibility for Xcel's revenue requirement among its customer classes?
- ***Fixed Customer Charges*—**Should the Commission approve the Company's proposed increases in the fixed customer charges?
- ***Energy Charge Credit*—**Should Xcel's energy charge credit be increased as proposed by the Chamber?
- ***Interruptible Service Discounts*—**Should the Commission approve Xcel's proposed increases in its interruptible service discounts?
- ***Coincident Peak Billing*—**Is any change to Xcel's Coincident Peak Billing practices warranted, as proposed by the Chamber?

These issues are examined individually below, with issues on which the Commission declines to accept the ALJ's recommendation discussed in greater detail.

III. The Administrative Law Judge's Report

The Administrative Law Judge's Report is well reasoned, comprehensive, and thorough. The ALJ held three days of formal evidentiary hearings and eight public hearings. He reviewed the testimony of expert witnesses offered by 11 parties, and related hearing exhibits. He reviewed written comments submitted by over 400 members of the public.

The ALJ received and reviewed initial and reply post-hearing briefs from the parties, as well as their proposed findings of fact and conclusions of law.

Based on this record, the ALJ made some 1,065 findings of fact and conclusions of law and made recommendations on stipulated, settled, and contested issues based on those findings and conclusions. The ALJ recommended that the Commission approve the Settlement, but in the alternative made several recommendations on Settlement-related issues if the Commission determined not to approve the settlement.

The Commission has itself examined the record, considered the report of the Administrative Law Judge, considered the exceptions to that report, and heard oral argument from the parties. Based on the entire record, the Commission concurs in most of the Administrative Law Judge's findings and conclusions. On some issues, however, the Commission reaches different conclusions, as delineated and explained below.

On all other issues, the Commission accepts, adopts, and incorporates the ALJ's findings, conclusions, and recommendations to the extent they are consistent with the decisions made herein.

FINANCIAL AND COST OF CAPITAL ISSUES

I. August 16, 2016 Stipulation of Settlement

A. Introduction

On August 16, 2016, Xcel filed a Stipulation of Settlement together with the Department, XLI, MCC, the Commercial Group, the SRA, Minneapolis, the ICI Group, and ECC (the Settling Parties).[13] The OAG, AARP, the CEOs, and the EFCA did not join in the Settlement. The OAG and AARP opposed aspects of the Settlement, while the CEOs and the EFCA took no position on it.

The Settlement resolves all revenue-requirement issues between the Settling Parties, as well as issues related to a medical-needs-customer bill-payment assistance program and LED street lighting. Beyond the assistance program and street lighting, the Settlement does not address class cost of service or rate design. Rather, the Settling Parties agreed that class cost of service and rate design would be resolved through the contested-case process already underway.

The Settlement is expressly conditioned on its acceptance by the Commission in its entirety; if the Commission modifies it in a manner that creates a "material adverse impact" to any Settling Party, that party may withdraw from the Settlement under the process outlined in the agreement. Under that process, the withdrawing party would file a motion to refer the rate case back to the Administrative Law Judge for further contested-case proceedings. The Settling Parties would then be free to argue their original positions on issues resolved by the Settlement.

B. Elements of the Settlement

1. Rate Increases

The Settlement, in essence, would result in a four-year multiyear rate plan spanning calendar years 2016 through 2019.

The Settling Parties agreed to specified increases in Xcel's electric rates each year, with the exception of 2018, when there will be no rate increase. In return, Xcel agreed not to file a general

[13] Minneapolis participated in the Settlement solely to support the resolution of street-lighting issues and took no position on the other issues addressed in the Settlement.

rate case for electric service prior to November 1, 2019, and to forego the use of riders, and limiting rider use to those already existing and specifically identified in a table attached to the Settlement.[14]

The Settling Parties agreed to a total rate increase of $184.97 million, or approximately six percent, over four years. The yearly rate increases—incremental and cumulative—are shown in the following tables:

	Incremental Increase			
	2016	2017	2018	2019
Rate increase in millions	$74.99	$59.86	–	$50.12
Percent increase	2.47%	1.97%	0.0%	1.65%

	Cumulative Increase			
	2016	2017	2018	2019
Rate increase in millions	$74.99	$134.85	$134.85	$184.97
Percent increase over current rates	2.47%	4.44%	4.44%	6.10%

2. 2016 Sales-Forecast True-up and Decoupling

a. 2016 Sales-Forecast True-up

In a rate case, the Commission ordinarily relies on a forecast of the utility's sales to both (1) determine the utility's test-year revenues at current rates and (2) set final rates sufficient to recover the test-year revenue requirement. In this case, however, the Settling Parties agreed that final rates should be set based on Xcel's actual, weather-normalized 2016 sales.[15]

On March 16, 2017, Xcel filed its actual, weather-normalized sales for 2016. Softer-than-expected sales meant that the Company sold approximately one million fewer megawatt-hours in 2016 than had been forecast at the outset of the case. Truing up the revenue shortfall added $59.99 million to the rate increase for 2016.

No party objected to the Settlement on the basis of the 2016 sales-forecast true-up, and, at hearing before the Commission, the Department and several other Settling Parties affirmatively indicated that the increase was acceptable.

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[14] August 16, 2016 Stipulation of Settlement, Attachment 3.

[15] Weather-normalized sales data are adjusted to remove the effects of extreme weather.

b. Decoupling

In general, if a utility's actual sales differ from forecasted sales, it over- or under-recovers its revenue requirement. However, a revenue-decoupling mechanism can be used to sever the link between sales and revenues, ensuring that the utility will recover the revenue requirement established in a rate case, even if the sales forecast over- or underestimates actual sales.

Under "full decoupling," a utility compares the revenues it collects in a given year with its Commission-approved revenue requirement and adjusts its rates to recover or refund the difference over the following year. Under "partial decoupling," actual revenues are weather normalized before the decoupling adjustment is calculated.

In Xcel's last rate case, the Commission approved full revenue decoupling for the Company's Residential and Small Commercial customer classes as a three-year pilot program.[16] The decoupling pilot program included a three percent cap on any upward rate adjustment, with a provision allowing Xcel to recover costs barred by the cap in succeeding years under certain conditions.

In this case, the Settling Parties propose to extend the decoupling pilot program by one year—through 2019—to match the term of the Settlement, and to use partial decoupling (i.e., sales true-ups based on weather-normalized data) in 2017–2019 for commercial and industrial customers who are not part of the full-decoupling pilot. Similar to the pilot program, any resulting rate increases to the partially decoupled classes would be capped at three percent.

3. Authorized ROE and Cost of Capital

In setting rates, the Commission must consider a utility's need for revenue sufficient to enable it to meet the cost of furnishing service, including a fair and reasonable return on investment.[17] One of the critical components of that fair and reasonable return on investment is the return on common equity (ROE), which, together with debt, finances the utility infrastructure.

The Settlement proposes that the Commission "allow Xcel Energy to represent its authorized ROE as nine and two-tenths percent (9.20%) for settlement purposes in this rate case Proceeding."[18]

The ROE figure has no effect on the Settlement's proposed revenue requirement, but it would allow Xcel to represent to financial markets that its authorized ROE is 9.2%, and to use this figure to initially calculate proposed rates for riders. Xcel acknowledged that the Settling Parties are free to advocate for a different ROE in future dockets and that the Commission may review ROE on a case-by-case basis in relevant dockets.

Xcel's overall cost of capital is derived from the sum of costs for long-term debt, short-term debt, and equity, weighted by the amount of each type of financing employed. The Settling

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[16] *See In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-13-868, Findings of Fact, Conclusions, and Order, at 77 (May 8, 2015).

[17] Minn. Stat. § 216B.16, subd. 6.

[18] Stipulation of Settlement, at 6.

Parties agreed that Xcel should be allowed to represent its capital structure as set forth in the following tables:

	2016			**2017**		
	Rate	Ratio	Wtd. Cost	Rate	Ratio	Wtd. Cost
Short-Term Debt	1.84%	1.26%	0.02%	3.57%	1.46%	0.05%
Long-Term Debt	4.81%	46.24%	2.22%	4.81%	46.04%	2.21%
Common Equity	9.20%	52.50%	4.83%	9.20%	52.50%	4.83%
Total			7.07%			7.09%

	2018			**2019**		
	Rate	Ratio	Wtd. Cost	Rate	Ratio	Wtd. Cost
Short-Term Debt	4.45%	1.09%	0.05%	4.31%	1.69%	0.07%
Long-Term Debt	4.77%	46.41%	2.21%	4.75%	45.81%	2.18%
Common Equity	9.20%	52.50%	4.83%	9.20%	52.50%	4.83%
Total			7.09%			7.08%

4. Customer Protections

Xcel confirmed that it would continue to file annual reports "with its actual recorded jurisdictional financials and earnings to provide transparency in its financial performance."[19] Further, the Settlement expressly recognizes the Commission's authority, under the multiyear-rate-plan Statute, Minn. Stat. § 216B.16, subd. 19(e), to examine the reasonableness of Xcel's rates during the term of its multiyear rate plan and to adjust those rates as necessary.

Xcel and the Department also maintained that Xcel would continue the practice, approved in the Company's last rate case, of performing a capital-projects true-up. In that case, the Commission approved a mechanism under which the Company would provide customers a refund if actual capital-project revenue requirements were lower than those included in rates.[20]

5. Provisional Recovery of Prairie Island Life-Cycle Management Costs and Use of Nuclear Expert

At the outset of Xcel's rate case, the Commission ordered that the record be developed on life-cycle management costs related to the Company's Prairie Island nuclear power plant, and whether such costs should be recovered on a provisional basis until such time as the Commission could review their prudency. It also authorized the Department to engage an expert to aid in this effort.

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[19] Burdick Rebuttal, at 5; *See* Minn. R. 7825.4700–.5400.

[20] *See In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-13-868, Findings of Fact, Conclusions, and Order, at 105 (May 8, 2015). In 2014, the true-up was calculated based on aggregate spending, while in 2015, it was calculated on a project-by-project basis. The Settlement adopts the aggregate-spending method used in 2014. The capital-spending true-up is one-way, meaning that the Company will make refunds if it spends less than it budgeted but cannot increase rates if it spends more.

The Settlement acknowledges that its proposed rate increases include Prairie Island life-cycle management costs and other nuclear capital costs. The Settling Parties agreed that there was no need for expert review of these costs at this time. They proposed instead that the Department retain a nuclear expert in Xcel's next resource-planning proceeding to examine the continued cost-effectiveness of the Company's nuclear fleet and evaluate the Company's planned capital and operations and maintenance (O&M) expenses, with the understanding that Xcel will continue to carry the burden of demonstrating the reasonableness of future rate increases.[21]

6. Interim-Rate Refund

The Settlement provides that Xcel will apply its cost of long-term debt (4.81 percent) to any interim-rate refund ordered by the Commission.

7. Deferral of 2016 Property Taxes

The Settling Parties agreed that Xcel would defer as a regulatory asset in 2016 an amount equal to the difference—not to exceed $28 million—between the property-tax expense approved for recovery in base rates in the Company's last rate case and its actual 2016 property-tax expense, and amortize the deferral evenly over a two-year period in 2018 and 2019.

The deferral is for accounting purposes only and would not impact the rate increases provided for in the Settlement.

8. Bill-Pay Assistance for Customers with Medical Needs

The Settling Parties agreed with ECC's proposal to use POWER ON, Xcel's existing bill-payment-assistance program for low-income ratepayers, as a model in developing a new bill-payment assistance program for medical-needs customers. The new program would do the following:

- Provide an affordability credit to limit the percentage of household income spent on electricity;
- Provide an arrearage-forgiveness component;
- Set income eligibility at 50 percent of the state median income, increasing to 60 percent if sufficient funds are available;
- Provide assistance on a first-come, first-served basis until program resources are exhausted;
- Cap administrative costs at five percent of the annual budget;
- Follow the reporting and program-funding-tracking procedures of POWER ON; and
- Recover program costs on the same basis as POWER ON.

[21] At hearing, Xcel confirmed that the Settlement does not provide for deferral of Prairie Island costs that are not recovered through the rates set in this case.

9. LED Street Lighting

The Settling Parties agreed to remove from this rate case all revenue requirements arising from capital additions for light-emitting diode (LED) streetlights and to use the lowered revenue requirement in setting final street-lighting rates.

Xcel would defer as a regulatory asset the revenue requirements directly related to actual LED-streetlight capital additions during the term of the Settlement, without interest, and credit LED street-lighting revenues against the deferral.

Minneapolis and the SRA agreed not to contest Xcel's recovery of the deferral in its next rate case but reserved the right to challenge the Company's claimed costs, alleged savings, and any other aspect of street-lighting rates.

10. Fuel-Clause Adjustment

The Settling Parties agreed that Xcel's Fuel Clause Adjustment mechanism (FCA), which the Company uses to recover the costs of fuel and purchased power, would be addressed according to the Commission's previous orders in the following dockets: E-999/CI-03-802, E-999/AA-12-757, E-999/AA-13-599, and E-999/AA-14-579.

11. Comparison of Company-Proposed, Department-Recommended, and Settlement Revenue Requirements

The table below compares the yearly revenue deficiencies for 2016–2019 as initially proposed by Xcel to the deficiencies calculated by the Department and to those ultimately reflected in the Settlement.

(000s)	2016	2017	2018	2019
Xcel Proposed	$194,612	$246,666	$297,133	$379,622
Department	$45,558	$99,406	$94,363	$189,049
Settlement	$74,990	$134,850	$134,850	$184,970

C. Issues Fully Resolved by the Settlement

Attachment 4 to the Settlement is titled "Issues Resolved for Settlement Purposes" and identifies 60 issues that the Settling Parties resolved among themselves. Most items are not explicitly resolved in the Settlement; the Settlement proposes a revenue requirement but does not establish specific adjustments to the Company's initially-proposed costs to reach its revenue requirement.

A subset of the 60 issues resolved among the Settling Parties were also not contested by any nonsettling party. The Commission considers these issues to be fully resolved by the Settlement:

- Overall Revenue Requirements
- Indexed ROE, Earnings Test, and Sharing Mechanism
- Sales Forecast and True-up
- Overall Operations and Maintenance (O&M) Expenses and Use of Escalators
- Energy Supply O&M Expenses

- Nuclear Non-Outage O&M Expenses
- Prairie Island Life-Cycle Management Capital Costs
- Prairie Island Spent-Fuel Storage Capital Costs
- Prairie Island Settlement Payments
- Prairie Island Reactor Coolant Pump Seals
- Monticello Spent Fuel Storage Capital Costs
- Monticello Cask 16
- Accumulated Deferred Income Taxes (ADIT)
- North Dakota Investment Tax Credits and Research and Experimentation (R&E) Tax Credits
- Minnesota Research and Experimentation (R&E) Tax Credits
- Protecting Americans from Tax Hikes (PATH) Act of 2015
- Property Taxes and True-up
- Health and Welfare Expenses
- Annual Incentive Plan Expenses
- 401 Nicollet Mall Building
- Cost Allocations – Transco Amortization
- Cost Allocations – Service Company
- Depreciation – Update for Remaining Lives Docket
- Changes to In-Service Dates – Transmission Projects
- Changes to In-Service Dates – Prairie Island Fire Protection
- Changes to In-Service Dates – Mankato Energy Center II
- Reclassification of Interruptible Sales to Firm
- Non-Asset-Based Trading
- Transmission Studies
- Courtenay Wind Land Lease
- Other Revenues – Three-Year Average
- Revenue Requirement for Fuel and Purchased Fuel
- MCC and EEI Dues (Lobbying)
- Rate-Case Expense Amortization
- Annual Compliance Filings on Cost of Debt and Capital Structure
- Interest Synchronization and Cash Working Capital
- Riders During Multiyear Rate Plan
- Capital Projects True-up
- Fuel Clause Adjustment
- Low-Income/Medical-Needs Discount Program
- LED Street Lighting

- Billing Format Issues
- Service Reliability (Non Revenue Requirements)
- Key Performance Indicators and Incentives
- Bill Documentation for Manual Bills

D. Issues Not Fully Resolved by the Settlement

AARP recommended that the Commission reject the Settlement or modify it significantly, arguing that it did not provide sufficient protections for consumers. The OAG, while not recommending that the Commission reject the Settlement, requested that if the Commission adopts the Settlement, it modify the Settlement's ROE and make findings on other issues the OAG raised.

The following issues, contested by the OAG, AARP, or both, were not fully resolved by the Settlement:

- Return on Equity
- Overall Cost of Capital
- Capital Budgeting
- Construction Work in Progress (CWIP)/Allowance for Funds Used During Construction (AFUDC)
- Business Systems – Productivity Through Technology (PTT) Expenses
- Employee Expenses
- Executive Compensation
- Revenues From Asset-Based Sales
- Interest Rate on Interim Rate Refund
- Depreciation-Reserve Amortization
- Wholesale Jurisdictional Allocation
- Nuclear Refueling Outage Accounting
- Length of Multiyear Rate Plan
- Performance Metrics
- Extension of Decoupling Pilot Program

E. Summary of Commission Action on Settlement

In the sections that follow, the Commission examines each objection to the Settlement maintained by a nonsettling party. In each case, the Commission concludes that the objection (1) is without merit and/or (2) does not justify disturbing a Settlement that, as a whole, will result in just and reasonable rates.

Finally, the Commission discusses the factors that led it to conclude that the Settlement will result in just and reasonable rates and should be approved. In brief, these factors include

- The participation of several sophisticated parties, representing all classes of Xcel's ratepayers, in the Settlement;
- The robust evidentiary record supporting the Settlement's proposed rate increases, revenue requirement, and ROE;
- The Settlement's substantial ratepayer benefits, including predictable increases, a rate freeze in 2018, limitations on the use of riders, and a capital-projects true-up; and
- The Settlement's recognition of the Commission's authority to review and adjust Xcel's rates at any time during the four-year Settlement term.

For these and other reasons discussed below, the Commission concludes that the Settlement is in the public interest and will result in just and reasonable rates.

II. Return on Equity

A. Summary

In determining just and reasonable rates, the Commission must

> give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, *and to earn a fair and reasonable return upon the investment in such property.*[22]

One of the critical components of that fair and reasonable return upon investment is the return on common equity (ROE). The Commission must set rates at a level that permits stockholders an opportunity to earn a fair and reasonable return on their investment and permits the utility to continue to attract investment.

In traditional rate cases, determining a fair and reasonable ROE is a necessary step in developing an overall rate of return that, when applied to the utility's rate base, yields a cost of capital that is used to calculate final rates. In contrast to the usual ROE approach, the Settlement proposes a revenue requirement without specifying a rate base and allows Xcel to represent a specified ROE as its authorized ROE. Thus, the Settlement ROE has no effect on final rates.

Having an authorized ROE is valuable to Xcel because it allows the Company to represent to current shareholders and to the broader market that it has the ability to earn this return. And, as discussed in more detail later, Xcel also uses its authorized ROE in calculating costs recovered through certain riders, and in computing AFUDC.[23]

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[22] Minn. Stat. § 216B.16, subd. 6 (emphasis added).

[23] Allowance for Funds Used During Construction, or AFUDC, is an accounting procedure by which the financing costs of funds used for construction are treated as income for purposes of offsetting rate-base treatment of the costs of construction work in progress.

Three of the Settling Parties—Xcel, the Department, and XLI—filed ROE analyses before joining the Settlement. The OAG filed testimony contesting the ROE set by the Settlement, and AARP concurred in the OAG's recommendation.

In the remainder of this section, the Commission evaluates the evidence on ROE and concludes that the Settlement's ROE of 9.20 percent is reasonable and supported by the record.

B. The Analytical Tools

Xcel is a subsidiary of Xcel Energy, Inc. and has no publicly traded common stock. Its ROE must therefore be inferred from market data for groups of companies that present similar investment risks, or "proxy groups."

Xcel, the Department, XLI, and OAG conducted cost-of-equity studies and based their analysis on proxy groups they considered similar enough to Xcel to serve as substitutes in determining the Company's cost of equity. All four parties used the Discounted Cash Flow (DCF) analytical model, on which this Commission has historically placed its heaviest reliance.

All four parties also used the Capital Asset Pricing Model (CAPM) as a secondary, corroborating resource, consistent with the Commission's historical treatment of this model. The Company also conducted a third analysis using the Risk Premium Model, which the Commission has historically relied on less heavily, considering the model prone to producing volatile and unreliable outcomes.

The DCF model uses the current dividend yield and the expected growth rate of dividends to determine what rate of return is high enough to induce investment. The model is derived from a formula used by investors to assess the attractiveness of investment opportunities using three inputs—dividends, stock prices, and growth rates. DCF modeling can be performed using constant-growth, two-growth, or multistage dividend-growth assumptions.

The CAPM model estimates the required return on an investment by determining the rate of return on a risk-free, interest-bearing investment and adding a historical risk premium determined by subtracting that risk-free rate of return from the total return on all market equities and multiplying the difference by beta, a measure of the investment's volatility compared with the volatility of the market as a whole.

The Risk Premium model determines the cost of equity by adding to current bond yields a premium reflecting the greater returns realized by equity holders over various historical periods.

C. Positions of the Parties

1. The Company

Before it entered into the Settlement, Xcel recommended a return on equity of 10.0 percent, based on a broad range of estimates from 8.95 percent to 11.39 percent generated by its analytical models and input assumptions.

The Company conducted a constant-growth DCF analysis, using a proxy group of 13 electric utility companies screened for comparability with Xcel in terms of operating profiles and investment risks. It obtained growth rates from three nationally recognized investment-research firms and applied those growth rates to the companies' average stock prices for the historical 30-, 90-, and 180-day periods ending September 30, 2015.

Xcel also performed a multistage DCF analysis, using near-term growth rates from the same three research firms and a long-term growth rate derived from forecasts of GDP growth and inflation. The Company performed a CAPM analysis, using 30-year Treasury bonds as the risk-free asset the analysis requires. And it performed a Risk Premium analysis, again using 30-year Treasury bonds as the baseline asset.

Xcel advocated that factors specific to its operating environment, including rising interest rates and planned capital investments, be considered in the development of ROE. The Company expects to make capital investments of approximately $6 billion between 2015 and 2019; it asserted that this projected spending, as a percentage of net utility plant, is higher than nine of the companies in its proxy group and higher than the median. These projected expenditures, it argued, add additional risk that requires a higher ROE.

2. The Department

The Department recommended a return on equity of 9.06 percent prior to joining the Settlement.

The Department conducted constant-growth and two-growth DCF analyses, using two proxy groups: an electric proxy group of 6 companies and a combination proxy group of 12 companies.[24] The Department used many of the same screening criteria as Xcel to arrive at its proxy groups. In addition, the Department applied a final screen to eliminate companies with an ROE of less than seven percent.

In contrast to Xcel, who used stock prices over three separate periods in 2015, the Department estimated share prices for its proxy companies using the average closing price over the 30 trading days ending May 26, 2016. The Department asserted that this period was long enough to avoid short-term volatility in stock while short enough to reflect recent market information.

Finally, the Department conducted CAPM and Empirical CAPM[25] analyses as a check on the reasonableness of its DCF analysis. Unlike Xcel, which used 30-year Treasury bonds as its riskless asset, the Department used 20-year Treasury bonds. The Department concluded that the results of its CAPM and Empirical CAPM analyses confirmed the reasonableness of its two-growth DCF results.

3. OAG

The OAG initially recommended a return on equity of 7.38 percent, the midpoint of its multistage DCF results. The OAG also performed constant-growth DCF and CAPM analyses as checks on the reasonableness of its multistage DCF analysis.

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[24] The combination proxy group comprised companies engaged in providing electric services in combination with other services, with electric services the major part though less than 95 percent of the total.

[25] Empirical CAPM is a method that attempts to adjust for the fact that CAPM tends to underestimate the ROE for companies with a beta smaller than one.

The OAG's initial proxy group was identical to Xcel's, although in rebuttal testimony it updated its group to exclude four companies that had recently announced merger and acquisition activity. The OAG opposed the Department's use of a combined proxy group, arguing that the ROE analysis should be focused on the risks of electric utilities. And it also disagreed with the Department's seven percent ROE screen, arguing that it improperly inserted the analyst's judgment into the analysis.

The OAG updated its ROE analysis in surrebuttal testimony using more recent market data, resulting in somewhat lower ROE estimates. It argued that, had Xcel and the Department performed a similar update, their analyses would also have shown a reduced ROE.

The OAG opposed Xcel's and the Department's use of flotation-cost adjustments in their ROEs. Flotation costs are the costs of issuing new shares of common stock, including preparation, filing, underwriting, and other expenditures. The OAG argued that the adjustments were not appropriate because Xcel did not issue any shares in 2015 and had no planned issuances for 2016–2018.

Finally, the OAG argued that the Settlement's 9.20 percent ROE was not tied to the record and expressed concern about its impact on ratepayers through riders and AFUDC. While the Settlement ROE would have no effect on Xcel's revenue requirement in this case, the Company uses its authorized rate of return to calculate costs collected from ratepayers through certain riders. Moreover, the OAG argued that the Settlement ROE, if applied to AFUDC, would overinflate Xcel's rate base.

For these reasons, if the Settlement is adopted, the OAG recommended that the Commission modify the Settlement's authorized ROE by lowering it from 9.20 percent to as low as 7.07 percent, but ultimately no higher than 8.14 percent. Alternatively, the OAG recommended that the Commission set a lower ROE for use in riders and the computation of AFUDC.

4. XLI

XLI's analysis resulted in an ROE range between 8.7 percent and 9.9 percent, with a midpoint of 9.3 percent. XLI recommended that if the Commission approves a multiyear rate plan, it set the Company's ROE below XLI's midpoint of 9.3 percent because a multiyear rate plan would reduce Xcel's risk.

XLI criticized Xcel's 10.0 percent ROE proposal, arguing that it relied too heavily on the Company's Risk Premium and CAPM analyses and gave insufficient weight to the traditional DCF analysis.

Like the OAG, XLI did not include flotation costs in its ROE analysis because Xcel would not be issuing stock in 2016–2019.

5. AARP

AARP did not perform an analysis of Xcel's ROE. It filed rebuttal testimony opposing the ROE set in the Settlement, arguing that 9.20 percent was too high, particularly in light of the OAG's recommended ROE of 7.38 percent.

D. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that the Settlement's authorized ROE of 9.20 percent was reasonable and supported by the record. But he recommended that, if the Commission does not approve the Settlement, it set an ROE based on the Department's analysis, which the ALJ found to be the most reasonable and best supported by the evidence.

1. Evaluation of Record Evidence on ROE

The ALJ determined, consistent with previous Commission decisions, that DCF modeling provided the best resource for determining a reasonable cost of equity. He found that only the Department used the CAPM analysis in the manner traditionally used in a utility rate case—to assess whether the CAPM results fall within the range of DCF results and thereby confirm the reasonableness of the DCF analysis.

The ALJ found that the parties had assembled appropriate proxy groups and screens. He rejected the OAG's argument that the Department's seven percent screen was unreasonable, noting that the OAG's ROE is an outlier compared to ROEs approved in other jurisdictions, falling below any authorized ROE for an electric utility in the United States in the past 30 years.

The ALJ found that the Department's market data were approximately four months older than the data the OAG used in surrebuttal. However, he found that the Department's data were reasonably updated and acceptable for use in ROE analysis—particularly in the context of a multiyear rate plan, where even the most recent market information will no longer be current by the end of the plan's term, and avoiding data that reflect anomalous market conditions becomes a more important consideration.

The ALJ rejected Xcel's argument that projected company-specific or market-wide risks warranted an upward adjustment to ROE. He noted that both Xcel and the Department used S&P credit ratings as screens for their proxy groups and reasoned that S&P could be expected to assess capital-expenditure plans and associated risk in its assessment of utilities' creditworthiness. Further adjusting ROE for company-specific risks would therefore double-count those risks.

Finally, the ALJ recommended a 0.10 percentage-point downward adjustment to the Department's recommended ROE to remove flotation costs. He observed that the Commission in recent rate cases had denied flotation costs where companies had no current plans to issue stock and had not provided evidence of an ongoing financial impact from earlier stock issuances.

2. Reasonableness of Settlement ROE

The Administrative Law Judge found the Settlement's ROE reasonable and supported by the record, finding that it was below the Company's currently authorized ROE of 9.72 percent and below the 2016 average of ROE decisions for vertically integrated utilities.

The ALJ concluded that the OAG's recommended ROE would not provide Xcel with a fair opportunity to earn a reasonable return throughout the term of the Settlement. He found that the OAG's ROE was not representative of returns set by the Commission and other regulatory bodies, both recently and in the past several decades.

Furthermore, the ALJ found that lowering the Settlement ROE, as advocated by the OAG, would likely be viewed by Xcel as having a material adverse impact and cause the Company to withdraw from the Settlement. He reasoned that lowering Xcel's authorized ROE would adversely impact its evaluation by credit-rating firms and current and prospective shareholders. And he similarly concluded that setting a lower ROE for purposes of riders and computing AFUDC would have a material adverse impact on the Company.

The ALJ found that the Settlement permits the Settling Parties to argue that an ROE other than the Settlement's authorized ROE should be used in other proceedings involving the Company, providing some protection if future circumstances point to a lower ROE as being appropriate. And he found that the OAG and AARP, as nonsettling parties, will be free to challenge ROE in future proceedings in any event.

E. Commission Action

The Commission concurs with the ALJ that the Settlement's authorized ROE of 9.20 percent is reasonable and supported by the record.

The Settlement ROE is below the Xcel's currently authorized ROE of 9.72 percent and below the 2016 average of ROE decisions for vertically integrated utilities. It is close to the Department's pre-Settlement recommendation of 9.06 percent. And it is within the ranges of Xcel's and XLI's ROE results, falling near the bottom of Xcel's 8.95–11.39 percent range, and just below the midpoint of XLI's 8.7–9.9 percent range.

The Commission agrees with the ALJ that, of the ROE analyses offered by the parties, the Department's is the most reasonable and best supported by the record evidence. The Settlement ROE is firmly supported by the Department's analysis.

While the four parties presenting evidence on ROE generally applied widely accepted analytical methods in an appropriate manner, only the Department performed consistently sound analyses in reaching its ROE recommendation. The Department used data from established investment-research firms. It applied the latest market data available at the time it submitted direct testimony. It eliminated from its proxy groups companies with ROEs too low to reasonably represent the risk of investing in an electric utility. And it applied its CAPM analysis purely as a check on the reasonableness of its primary, DCF analysis.

The Settlement's ROE is significantly higher than the OAG's recommended range of 7.07–8.14 percent. However, the OAG fails to explain how its recommendation is reasonable or supportable in light of the overwhelming evidence of the range of reasonable ROEs in the record. The Commission finds that an ROE in the OAG's recommended range would not permit Xcel to earn a return sufficient to induce investors to purchase company stock, given the risk associated with investing in an electric utility.

The OAG recommended that the Commission modify the Settlement by lowering the authorized ROE. Alternatively, it recommended that the Commission set a lower ROE for use in riders and the computation of AFUDC.

While modifying the Settlement ROE would have no effect on the proposed rate increases, it could adversely impact Xcel's evaluation by credit-rating firms and current and prospective shareholders. And setting a lower ROE for purposes of riders and AFUDC would directly affect the costs Xcel is allowed to recover in those contexts. The Commission thus concludes that either modification would likely prompt Xcel to withdraw from the Settlement, necessitating further, costly contested-case proceedings.

More importantly, the OAG's recommendation to modify the Settlement ROE is not reasonable because the OAG's recommended ROE is not supported by a preponderance of the evidence on the record. Because the Settlement does not prevent any party from contesting the ROE when it is applied in rider dockets or other proceedings, if future circumstances suggest that a lower ROE is appropriate in other contexts, parties will be free to assert an alternative ROE at that time.

For the foregoing reasons, the Commission finds the Settlement's 9.20 percent ROE reasonable.

IV. Performance Metrics

A. Introduction

Under Minn. Stat. § 216B.16, subd. 19, the Commission may require a utility proposing a multiyear rate plan to provide a "set of reasonable performance measures and incentives that are quantifiable, verifiable, and consistent with state energy policies."[26] Alternatively, the Commission "may initiate a proceeding to determine a set of performance measures that can be used to assess a utility operating under a multiyear rate plan."[27]

Xcel's existing performance metrics are set forth in its Quality of Service Plan (QSP) Tariff. The QSP Tariff is the product of negotiations with the Department, the OAG, and the SRA, and has been approved by the Commission. It is penalty-based and tracks eight metrics, including reliability, customer complaints, call response time, billing accuracy, and others.

The Settlement does not propose any new performance metrics. However, prior to settling, Xcel proposed new performance metrics addressing customer satisfaction, customer choice, environmental stewardship, and customer outage experience. The Company did not propose to tie its performance under these categories to any financial penalties or incentives.

B. Positions of the Parties

The Department argued that, before a new performance metric can be evaluated, much more detail needs to be provided about what exactly would be measured, how the data are to be collected, and what behaviors are being targeted for change. It recommended that the Commission open a separate proceeding to evaluate Xcel's proposed metrics, craft additional metrics, and consider whether to tie any financial penalties or incentives to the Company's performance under those metrics.

The OAG, similarly, recommended that the Commission initiate a proceeding to determine a set of performance metrics that can be used to assess a utility operating under a multiyear rate plan, as specified by statute.

[26] Minn. Stat. § 216B.16, subd. 19(a).

[27] *Id.*, subd. 19(h).

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found the record insufficient to support the establishment of any new performance metrics for the multiyear rate plan. He recommended that the Commission open a separate proceeding to examine appropriate metrics and consider linking the metrics to financial penalties or incentives.

D. Commission Action

The Commission concurs with ALJ and will open a separate docket to identify and develop performance-based metrics and standards—and potentially incentives—to be implemented during the multiyear rate plan.[28] The Commission will delegate to its Executive Secretary authority to issue notices, set a schedule, and designate comment periods for the docket.

Performance metrics are an important tool to preserve service quality and align utility incentives with ratepayer interests, particularly in the context of a Settlement that establishes rate increases for multiple years. However, the record in this case is not sufficiently developed to determine the adequacy of Xcel's proposed performance metrics—or what other measures of performance might be established in place of or in addition to Xcel's metrics.

Moreover, the Commission is not satisfied, on this record, that the Company has given full consideration to the potential for coupling performance metrics with financial incentives. The Commission concludes that a new docket will provide the best venue for determining what combination of metrics and incentives, in addition to those already in Xcel's QSP Tariff, would appropriately align utility and ratepayer interests.

V. Extension of Decoupling Pilot Program

A. The Issue

As discussed, the Settlement would extend by one year the decoupling pilot program established for Residential and Small Commercial customer classes in Xcel's last rate case.

AARP argued that extending the decoupling pilot program by a year would deny consumers the reassurance that data from the current pilot would be reviewed before a decision is made to extend the program. More specifically, it argued that decoupling shifts risks to ratepayers, insulates the utility from the risk of declining sales, causes high-usage customers to subsidize low-usage customers, and rewards the utility for energy savings it did not bring about. AARP advocated that decoupling surcharges be capped at two percent to preserve affordability.

The Administrative Law Judge deemed AARP's concerns sensible but reasoned that the Commission had already weighed these concerns along with others when it approved the three-year decoupling pilot. He found it reasonable to extend the decoupling pilot to match the term of the Settlement.

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[28] *In the Matter of a Commission Investigation to Identify and Develop Performance-Based Metrics, and Potentially Incentives, for Xcel Energy's Electric Utility Operations*, Docket No. E-002/CI-17-401.

B. Commission Action

The Commission agrees with the ALJ that extending the decoupling pilot program by one year to match the term of the Settlement is reasonable and adopts his findings and conclusions on this issue. Making the term of the pilot program co-extensive with the four-year term of the Settlement will conserve Commission, party, and ratepayer resources by allowing the pilot to be evaluated at the same time as Xcel's next rate case, should it choose to file one at the conclusion of the four-year Settlement term.

Moreover, the Commission has already determined that the decoupling pilot program has sufficient ratepayer protections, including customer education and outreach requirements, annual reporting requirements, and a three percent cap on upward adjustments to the rates of any single customer class. The Settlement leaves these existing protections in place for the extra year that the pilot is in effect.

VI. Capital Budgeting

A. The Issue

A substantial portion of the rate increases proposed under the Settlement are driven by anticipated capital spending.

The OAG contended that Xcel has a history of significantly overestimating its capital spending, claiming that the Company's 2015 budget overstated actual capital investments by 21 percent. The 2015 overbudgeted amount was refunded to ratepayers under the capital-projects true-up ordered in the Company's last rate case.[29]

The OAG argued that Xcel needs an incentive to budget more accurately.

Xcel disputed the OAG's claim that its 2015 capital-project costs exceeded estimates by 21 percent. It argued that the cost difference was primarily due to projects being completed later than expected. And it maintained that the true-up mechanism worked as intended, providing customers with a refund plus interest due to the project timing differences.

The Administrative Law Judge found that the four-year rate plan established by the Settlement poses some difficulty for capital budgeting, in that unexpected events can occur that require a redeployment of resources to provide safe and reliable service. However, he found that ratepayers would be protected from overbudgeting through the Settlement's capital-projects true-up provision.

B. Commission Action

The Commission agrees with the Administrative Law Judge that the capital-projects true-up will provide ratepayers with significant protection against capital-spending overbudgeting. And while the record is not sufficiently developed to adopt the OAG's recommendation for a budget-

[29] *See In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-13-868, Findings of Fact, Conclusions, and Order, at 108 (May 8, 2015).

accuracy incentive, such an incentive could be considered in the proceeding to explore potential performance metrics and incentives discussed in section III above.

Xcel's budget for 2016–2018 includes approximately 1,810 capital projects. In contrast to some past rate cases, there are not many extremely large projects planned; Xcel estimates that the largest 335 discrete projects account for approximately 90 percent of the total anticipated spending.

Under these circumstances, the aggregate spending data used in the capital-projects true-up will provide little indication of cost over- or under-runs that may occur on individual projects. While there may be too many projects in Xcel's capital budget to require reporting at the per-project level, it would be beneficial, for regulatory-review purposes, to have the Company file more information about its capital projects than just the overall spending in a given year.

Accordingly, the Commission will direct Xcel to work with Commission and Department staff to develop an annual capital-projects true-up compliance report that meets the regulatory needs of the agencies. This will allow the agencies to review Xcel's capital spending at a more granular level while considering ways to ease the administrative burden of reporting on 1,810 capital projects.

VII. Construction Work in Progress (CWIP) / Allowance for Funds Used During Construction (AFUDC)

A. Introduction

Construction Work in Progress (CWIP) and Allowance for Funds Used During Construction (AFUDC) are accounting devices used to permit utilities to recover the financing costs of capital projects while they are under construction. The Commission is authorized to consider CWIP and AFUDC in ratemaking under Minn. Stat. § 216B.16, subds. 6 and 6a.

Capital costs incurred during construction are placed in rate base as CWIP; the associated financing costs are added to net operating income as AFUDC, normally offsetting any return on CWIP until the plant under construction goes into service. At that time, CWIP and AFUDC are recovered over the life of the asset through the recording of book depreciation expense.

The Commission has been following this approach in Xcel rate cases since 1977.

B. Positions of the Parties

The OAG argued that the rate of return that Xcel receives on AFUDC results in the Company's retail rates being among the highest in the region. To better protect ratepayers, the OAG made three recommendations:

- First, the OAG recommended that the rate of return allowed on AFUDC should either be calculated as a 50/50 blend of short- and long-term interest rates on debt or be set at the prime rate.
- Second, it recommended that the Commission follow the Federal Energy Regulatory Commission's (FERC's) prohibition against allowing AFUDC to be accrued on projects that have been dormant three months or longer "unless the Company can justify the interruption as being reasonable under the circumstances."

- Third, the OAG recommended that the Commission prohibit AFUDC on construction projects budgeted at less than $5 million.

Xcel contended that it does comply with FERC's rules with respect to AFUDC. It maintained that the Commission has repeatedly approved the inclusion of AFUDC and CWIP in rate cases and has explicitly rejected similar recommendations by the OAG in recent cases, and it argued that the OAG had not presented the Commission with new information or arguments for changing course.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge agreed that the Settlement is consistent with the Commission's past practice with respect to CWIP and AFUDC, and that the OAG had not presented new evidence or argument for changing that practice. He therefore found the Settlement's treatment of CWIP and AFUDC reasonable.

D. Commission Action

The Commission agrees with the ALJ that the Settlement's treatment of CWIP and AFUDC is reasonable and adopts his findings and conclusions on this issue.

The OAG has not advanced any new arguments or evidence to support its AFUDC proposals. Moreover, the alternative to AFUDC is directly expensing interest costs, which has a larger immediate impact on rates than capitalizing the costs. Xcel estimated that, due to the amount of CWIP in its rate base that is now offset by AFUDC, the OAG's proposal would increase the Company's revenue requirement for 2016 by $19.3 million.

Under the circumstances, the Commission will decline to depart from established practice with respect to CWIP and AFUDC.

VIII. Business Systems – Productivity Through Technology (PTT) Expenses

"Productivity Through Technology" refers to Xcel's efforts to replace its General Ledger and several Work and Asset Management Systems that have reached the end of their useful lives. Xcel originally included $131.5 million in rate base for PTT projects, $4.2 million in PTT-related operation and maintenance (O&M) expenses in the 2016 test year, and significant PTT depreciation expense in the test year and the 2017 and 2018 plan years.

The OAG argued that Xcel should reduce its PTT expenses by the savings realized through PTT projects. It reasoned that, since ratepayers are paying the cost of PTT-related plant additions, depreciation, and O&M, they should receive the cost savings generated from these initiatives.

Xcel acknowledged that efficiencies from PTT projects allow the Company to avoid additional O&M costs that it would otherwise incur; however, Xcel argued that projected savings from PTT are already reflected in the test-year budget.

The ALJ found that Xcel had not met its burden to show that its budget took into account cost savings from PTT, reasoning that the Company should be able to more precisely quantify the savings that will result from such a significant investment. However, the ALJ did not recommend rejecting the Settlement over the issue of PTT savings.

The Commission concurs with the Administrative Law Judge and adopts his findings and conclusions on this issue. While Xcel should be able to better quantify the expected savings from PTT, the Commission agrees that this is not a sufficient basis to reject or modify a settlement that, on the whole, results in just and reasonable rates.

IX. Employee Expenses

Minn. Stat. § 216B.16, subd. 17(a), bars the recovery of employee travel and entertainment expenses that the Commission deems unreasonable and unnecessary for the provision of utility service.

The Settlement does not explicitly include an adjustment for employee expenses. However, Xcel initially included $15,041,247 in employee travel and entertainment expenses in its 2016 test year.

The OAG argued that the Commission should disallow certain travel and entertainment expenses because they were unnecessary for the provision of utility service. The expenses that the OAG objected to related to a work celebration, regularly scheduled department meals, voluntary employee social clubs, and individual coaching sessions. The OAG initially recommended disallowing $76,027 in employee expenses.

In its rebuttal testimony, Xcel agreed to remove roughly a third of the amount that the OAG recommended be excluded, and the OAG dropped certain disputed items. Following these adjustments, some $25,622 in 2016 test-year employee expenses remained in dispute.

The Administrative Law Judge found that the challenged expenses were related to Xcel's operations and were not unusual or extraordinary for an established business. He noted that the Settlement reflects a substantially reduced overall revenue requirement and reasoned that this reduction would cause the Company to revise its budgets and reduce expenses, including employee expenses. Consequently, he recommended no adjustment to travel and entertainment expenses if the Commission approves the Settlement.

The Commission concurs with the Administrative Law Judge that no adjustment to the Settlement is warranted based on the disputed employee expenses. The Commission will adopt the ALJ's findings and conclusions on this issue.

X. Executive Compensation

Xcel's revenue requirement included compensation expenses for Benjamin Fowke, the CEO of Xcel, and Chris Clark, the president of Xcel for Minnesota, South Dakota, and North Dakota.

The OAG recommended that the Commission disallow 100 percent of Mr. Fowke's compensation and expenses and 50 percent of Mr. Clark's compensation and expenses, arguing that these percentages of their compensation are directed solely to increasing earnings, which does not benefit ratepayers.

Xcel challenged the OAG's assertion that its executives focus their efforts on increasing earnings and argued that, in any event, the Company's earnings contribute to its financial health, which benefits ratepayers by allowing the utility access to capital markets on favorable terms and lowering the overall cost of service. Xcel also presented evidence that its executives are paid at or below market levels, which the OAG did not dispute.

The ALJ concluded that executive services, like any other expense, must be obtained at a reasonable cost to be recoverable. He found that the OAG did not provide a basis for distinguishing between executive time that increased earnings without any collateral benefit to ratepayers and executive time that did provide a collateral benefit. He did not recommend rejecting or modifying the Settlement based on executive compensation.

The Commission concurs with the Administrative Law Judge and will adopt his findings and conclusions on this issue. The executive-compensation amounts appear to be reasonable, and the OAG's arguments are not sufficient to introduce doubt about their reasonableness.

XI. Revenues from Asset-Based Sales

When Xcel has unused or underutilized generation capacity, it seeks to the sell power on a wholesale basis to other utilities ("asset-based sales"). In 2015, approximately nine percent of Xcel's sales were to wholesale customers.

The OAG expressed concern that Xcel has recently increased its generation capacity while at the same time contending that sales are stagnant, leading to increased opportunities for asset-based sales. The OAG argued that the Company's test-year revenues for asset-based sales should be increased by $19.1 million to recognize what, in the OAG's view, was an excessive level of generation capacity.

Xcel responded that the Commission had approved all its capacity additions. As a member of MISO,[30] the Company must make its excess capacity available on the MISO market at marginal cost. Xcel stated that it credits ratepayers with 100 percent of the margins from its sales on the MISO market through the Fuel Clause Adjustment rider.

The Administrative Law Judge did not recommend rejecting or modifying the Settlement based on asset-based sales. He found that Xcel is essentially a price-taker, obliged to offer its excess power at marginal cost, and that the OAG had not explained how the Company could increase its wholesale revenues under these circumstances.

The Commission concurs with the Administrative Law Judge that Xcel's asset-based sales amounts are reasonable and will adopt his findings and conclusions on this issue.

[30] The Midcontinent Independent System Operator (MISO) operates the upper Midwest transmission system.

XII. Interest Rate on Interim-Rate Refund

A. The Issue

When the Commission orders interim rates into effect during a rate case, but ultimately approves final rates that are lower than interim rates, Minn. R. 7825.3300 requires that the utility refund the difference to its customers, "including interest at the average prime interest rate computed from the effective date of the [interim] rates through the date of refund." As of May 2017, the prime rate was 4.00 percent.

The Settlement provides for an interim-rate refund with interest at 4.81 percent, which is Xcel's cost of long-term debt.

The OAG recommended that any refund include interest at a higher interest rate than has historically been used for interim-rate refunds. Specifically, it recommended a rate of 1.5 percent per month, or 18 percent on an annual basis. The OAG argued that such a rate, in addition to making ratepayers whole, would give Xcel an incentive to make more accurate cost projections.

The ALJ found the OAG's recommended interest rate of 18 percent excessive and found the Settlement's 4.81 percent rate reasonable.

B. Commission Action

The Commission concurs with the ALJ, will grant a variance to Minn. R. 7825.3300, and will order that an annual 4.81 percent interest rate be used to calculate interim-rate refunds in this case. Applying Minn. R. 7829.3200's standard for granting rule variances, the Commission finds as follows:

1. Enforcement of Minn. R. 7825.3300 would impose an excessive burden on ratepayers because it would prevent them from receiving a higher interest rate voluntarily offered by the Company.
2. Granting a variance to the rule would not adversely affect the public interest, but in fact would promote the public interest by providing ratepayers with a benefit that no party opposes.
3. Granting the variance would not conflict with standards imposed by law because the Commission is expressly authorized to set the interest rate that applies to interim-rate refunds under Minn. Stat. § 216B.16, subd. 3(c).

Finally, the Commission agrees with the ALJ that the OAG's recommendation to require an interim-rate refund with 18 percent interest would unreasonably burden Xcel, and would in fact only be an incentive by virtue of being punitive.

XIII. Depreciation-Reserve Amortization

For a time, Xcel underestimated the useful life of certain assets and consequently recorded depreciation expense in excess of the assets' actual depreciation. The excess recorded depreciation expense gave rise to a "depreciation-reserve surplus," which, by 2012, had reached $261 million.

In Xcel's 2012 and 2013 rate cases, the Commission directed the Company to return this depreciation-reserve surplus to ratepayers by amortizing it, initially, over an eight-year period,[31] and, later, over a three-year period.[32] This resulted in a lower annual depreciation expense for the assets at issue than would have occurred without the amortization. However, it also meant that the portion of these assets that remained in rate base, upon which the Company earns a return, was higher than it otherwise would have been.

The OAG recommended that the rate-base increase that resulted from amortizing the depreciation-reserve surplus—or $261 million—should cease earning a return. The OAG contended to allow this sum to earn a return going forward would be to permit Xcel's shareholders to recover a return on these assets twice.

Xcel argued that the Commission, in ordering amortization of the depreciation-reserve surplus, understood that amortization would reduce rates in the near term but increase rates in future years. By reducing depreciation, the Company recovers its investment more slowly, and shareholders are compensated for this delay by receiving a return on the undepreciated portion of the assets.

The Administrative Law Judge did not find that the amortization of the depreciation-reserve surplus provided a double recovery and did not recommend rejecting or modifying the Settlement on the basis of depreciation reserve.

The Commission concurs with the Administrative Law Judge that Xcel's amortization of its depreciation-reserve surplus was appropriate and does not result in double recovery. The Commission will adopt the ALJ's findings and conclusions on this issue.

XIV. Wholesale Jurisdictional Allocation

In November 2013, a group of wholesale transmission customers filed a complaint with the Federal Energy Regulatory Commission (FERC), which oversees regional energy markets, alleging that MISO transmission owners, of which Xcel is one, were receiving too high a return on equity through their transmission rates. A second complaint was filed by a separate group of customers in February 2015.

Xcel credits its retail customers, through the Transmission Cost Recovery (TCR) rider, with the margins it earns from selling wholesale transmission services. The Company proposed that, if FERC orders a lower transmission ROE, resulting in decreased wholesale transmission revenues, the decrease be reflected in TCR rider rates.

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[31] *See In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-12-961, Findings of Fact, Conclusions, and Order, at 29 (September 3, 2013).

[32] *See In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-13-868, Findings of Fact, Conclusions, and Order, at 50–51 (May 8, 2015).

The OAG criticized Xcel's proposal, arguing that the Company's Minnesota retail customers would, in effect, be insuring Xcel against an adverse ROE decision in another jurisdiction. The OAG recommended that Xcel reinstitute its practice of allocating costs between wholesale and retail "jurisdictions," similar to how the Company allocates costs among the states in which it operates.

The Settlement does not require Xcel to reestablish its wholesale jurisdiction. But, the Administrative Law Judge concluded that the OAG had not demonstrated that Minnesota retail customers would benefit from the reestablishment of a separate wholesale jurisdiction, noting that Xcel credits its retail customers with the margins from wholesale services.

The Commission concurs with the Administrative Law Judge that Xcel's proposal to reflect decreased wholesale transmission revenues in the TCR rider is reasonable and adopts his findings and conclusions on this issue.

XV. Nuclear-Refueling-Outage Accounting

Since the conclusion of its 2008 rate case, Xcel has been deferring and amortizing its nuclear-refueling-outage costs. The Commission approved this cost treatment to ensure greater accuracy in cost recovery by reasonably matching the time these costs are incurred with the time they are recovered while avoiding substantial fluctuations between rate cases.

The Commission has in the past approved a carrying charge—calculated at Xcel's overall rate of return—to compensate the Company for the time value of money forgone as part of this deferred recovery. The Settlement does not change the Commission's past practice with respect to the treatment of nuclear refueling costs.

The OAG objected to allowing Xcel to earn its full rate of return on the deferred, unamortized refueling-outage costs. It recommended that either no carrying charge be allowed on these costs, or that only a reduced rate of return be allowed, such as Xcel's cost of short-term debt.

The Administrative Law Judge did not recommend rejecting or modifying the Settlement based on this issue. He recommended that, if the Commission does not approve the Settlement, it consider applying an intermediate-term rate of return to the costs.

While examining the carrying charge for deferred refueling-outage costs may be a worthwhile exercise in a future rate case, the Commission concludes that this is not a sufficient basis to disturb a settlement that, on the whole, results in just and reasonable rates.

XVI. Length of Multiyear Rate Plan

Minn. Stat. § 216B.16, subd. 19, permits a utility to propose a multiyear rate plan of up to five years. Xcel initially proposed both three-year and five-year rate plans; the Settlement would result in a four-year rate plan.

The OAG and AARP both expressed concerns about multiyear rate plans.

The OAG argued that Xcel's multiyear-rate-plan proposals represent a significant change from historical practice, where rates are set based on a company's known and anticipated expenses for a test year. By contrast, under Xcel's rate-plan approach, the Commission's determination of just and reasonable rates will inform the Company's budget decisions for several years. The OAG argued that this gives Xcel an incentive to minimize its operating budget to maximize shareholder returns; yet ratepayers may not want certain operating expenses, such as maintenance expenses, minimized.

AARP was primarily concerned with what it viewed as the Commission's loss of practical oversight of Xcel's rates during a multiyear rate plan. It argued that the Commission cannot perform a full review of a utility's proposed rates, or provide customer protections, if the utility has "an automatic path" to higher rates with only an annual check-in.

The Administrative Law Judge found that the Settlement's four-year rate plan comported with the Legislature's clear authorization of multiyear rate plans of up to five years. He reasoned that this authorization necessarily entailed that Xcel be allowed to adjust its budgets as necessary to address changing circumstances over the term of the rate plan.

The Commission concurs with the Administrative Law Judge and adopts his findings and conclusions on this issue. While Xcel will not be filing another rate case until at least November 2019, the Commission retains the authority, throughout the term of the multiyear rate plan, to examine the reasonableness of Xcel rates and to adjust them as necessary. The Commission will thus maintain oversight of the Company's rates during the term of the Settlement, allowing it to investigate any claim that the Company is overearning.

XVII. Settlement Approved

A. The Legal Standard

Under the Public Utilities Act, utilities seeking a rate increase have the burden of proof to show that the proposed rate change is just and reasonable.[33] Any doubt as to reasonableness is to be resolved in favor of the consumer.[34]

The Act also encourages settlements. Before beginning contested case proceedings on a general rate case, administrative law judges are required to convene a settlement conference for the purpose of encouraging settlement of some or all of the issues in the case. They are authorized to reconvene the settlement conference at any point before the case is returned to the Commission, at their own discretion or at the request of any party.[35]

The Commission is authorized to accept, reject, or modify any settlement. It can accept a settlement only upon finding that to do so is in the public interest and is supported by substantial evidence.[36]

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[33] Minn. Stat. § 216B.16, subd. 4.

[34] Minn. Stat. § 216B.03.

[35] Minn. Stat. § 216B.16, subd. 1a (a).

[36] Minn. Stat. § 216B.16, subd. 1a (b).

B. Positions of the Parties

1. The Settling Parties

The Settling Parties agreed that the revenue increases in the Settlement are just, reasonable, and in the public interest. They asserted that the proposed rate increases are moderate, amounting to 6.1 percent, or $187.97 million, over four years before accounting for the initial 2016 sales true-up. And even with the $60 million baseline increase that resulted from this initial sales true-up, the Settling parties continued to support the Settlement because of its other benefits, which included a three-percent cap on future sales-true-up-related rate increases, limits on new rate riders, and the guarantee that Xcel would not file another rate case for four years.

2. The OAG

The OAG criticized what it perceived as a lack of record support for the Settlement's revenue requirement, arguing that the did not provide the type of detailed financial information that the Commission typically considers in a rate case, such as a rate base, income statement, and rate of return. And it argued that the rate increase under the Settlement was larger, as a percentage of Xcel's initial request, than the increases approved by the Commission in past rate cases.

The OAG argued that the Commission should not adopt the Settlement without considering the issues raised by nonsettling parties, making specific findings on those issues, and modifying the Settlement where warranted. The OAG did not recommend any specific adjustments to the Settlement's revenue requirement, but it did recommend that the Commission lower the Settlement's authorized ROE or, alternatively, set a lower ROE for use in riders and the calculation of AFUDC.

3. AARP

AARP argued that the Commission should reject the Settlement or significantly modify it to protect Residential customers. It argued that multiyear rate plans create risks for consumers and recommended that the Commission adopt a two-year rate plan rather than the Settlement's four-year plan. And it agreed with the OAG that the Settlement's ROE was too high and argued that there should be a profit-sharing mechanism to protect ratepayers if circumstances later show that a lower revenue requirement is warranted.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the Settlement would contribute to establishing just and reasonable rates and that none of the objections to adopting it were sufficient to merit its rejection. He therefore recommended that the Commission approve the Settlement.

The ALJ found the Settlement's overall revenue requirement just and reasonable, finding that it was consistent with the Department's recommended revenue adjustments, including its recommended ROE. He found the Settlement's authorized ROE of 9.20 percent reasonable and supported by the record for the reasons explained in his evaluation of the parties' ROE analyses.

The ALJ also found the yearly rate increases reasonable based on their being less than independent measures of inflation and significantly less than what Xcel initially proposed. He also found it significant that the Settlement proposes no rate increase in 2018 and prohibits Xcel from filing another rate case until November 2019, giving the parties and ratepayers relief from annual rate-case proceedings. And he found that the Settlement provides rate payers further relief by prohibiting the Company from seeking to institute any new riders for four years.

The ALJ concluded that the reasonableness of the Settlement was further supported by ratepayer protections, including true-ups for sales, capital spending, and property taxes. He observed that the capital-spending true-up is one-way, meaning that the Company will make refunds if it spends less than it budgeted but cannot increase rates if it spends more. And he found that the Settlement does not affect the Commission's authority to investigate, examine, and adjust the Company's rates during the term of the plan.

The ALJ rejected the OAG's criticisms of the Settlement. He reasoned that, although the Settlement does not provide an itemization of costs, the record contains substantial evidence of how Xcel developed its proposed cost of service, as well as the Department's recommended adjustments. He found that the Settlement sets a just and reasonable overall limit on rate increases and reasoned that each cost-of-service component need not be separately determined.

Finally, the ALJ rejected AARP's arguments against the Settlement. In particular, he did not find the Settlement's lack of a profit-sharing mechanism or its four-year term to be an adequate basis for rejecting the Settlement because the Commission will retain the authority during the term of the multiyear rate plan to investigate excessive rates and order them lowered.

D. Commission Action

The Commission finds that the August 16, 2016 Stipulation of Settlement will result in just and reasonable rates, is supported by substantial evidence, and that adopting it is in the public interest, and will therefore approve it. A number of factors, many of which have been touched upon in preceding sections of this order, inform the Commission's decision to approve the Settlement.

First, while the Settlement does not include all parties—the OAG's absence being the most notable—it is joined by a number of sophisticated parties representing a broad range of interests. The participation and unified support of this diverse set of parties, representing all classes of Xcel's ratepayers, affords significant assurance that the agreement they jointly reached will result in just and reasonable rates.

Compellingly, the Settlement is based on a smaller revenue requirement than that recommended by the Department—the one party charged with representing the general public interest. This gives the Commission great confidence that the Settlement will result in just and reasonable rates.

Second, the parties to this case—both settling and nonsettling—developed a robust evidentiary record by which to judge the Settlement. This record includes direct testimony on all revenue-requirement-related issues, rebuttal and surrebuttal testimony on issues disputed by nonsettling parties, extensive briefing, and an ALJ recommendation on all contested issues.

In particular, the record includes extensive evidence and findings on ROE. Although the ROE does not affect the Settlement's revenue requirement, is important for Xcel in representing its financial health to the investment community and will allow the Commission to judge whether the Company's earnings are reasonable over the four-year Settlement term. For the reasons discussed earlier, the Commission declines to modify the Settlement's authorized ROE for purposes of riders or AFUDC calculations.

Third, the Settlement includes substantial ratepayer protections and other provisions that will provide rate stability and certainty over the four-year rate plan, while reducing the litigation burden on private and public intervenors. The Settlement sets forth maximum rate increases for each year, including a rate freeze in 2018; limits riders to those specifically identified; and ensures that Xcel will not seek another rate increase until 2020. And, as previously discussed, it includes a capital-projects true-up to ensure that ratepayers do not pay budgeted costs for capital projects unless those costs are actually incurred.

Fourth, the Settlement expressly recognizes the Commission's authority under the multiyear-rate-plan statute to review and adjust the rates that result from the Settlement at any time during the four-year term.[37] And it obliges Xcel to continue to file annual reports "with its actual recorded jurisdictional financials and earnings to provide transparency in its financial performance."

Finally, the rate increase resulting from the Settlement is in line with inflation and is consistent with the outcomes of prior Xcel rate cases. The following table shows the rate increases that were granted in Xcel's last four rate cases as a percentage of the Company's initial request in each case:

Docket No.	Request ($ millions)	Increase ($ millions)	Percent Approved
E-002/GR-08-1065	$156.07	$91.38	58.5%
E-002/GR-10-971	$198.50	$72.85	36.7%
E-002/GR-12-961	$285.48	$102.80	36.0%
E-002/GR-13-868	$291.20	$149.42	51.3%
Settlement	**$379.62**	**$184.97**	**48.7%**

The fact that the rate increase allowed by the Settlement—as a percentage of the Company's initial request—is in line with those granted in prior, litigated cases is further evidence of its reasonableness.

For all these reasons, and based on its evaluation of contested issues in the preceding sections, the Commission will approve the August 16, 2016 Stipulation of Settlement in its entirety.

[37] *See* Minn. Stat. § 216B.16, subd. 19 (providing that, "[a]t any time prior to conclusion of a multiyear rate plan, the commission, upon its own motion or upon petition of any party, has the discretion to examine the reasonableness of the utility's rates under the plan, and adjust rates as necessary").

XVIII. Settled Issues – Housekeeping Items

A. Changes to In-service Dates – Mankato Energy Center II

Mankato Energy Center II (Mankato II) is a 345 MW gas-powered generator being built by Calpine Corporation in Mankato. Xcel has a power purchase agreement (PPA) with Mankato II that the Commission approved in February 2015.[38] The Company included Mankato II capacity-payment costs in its 2018 plan year; however, the generator's in-service date has since been extended to June 2019.

The Commission will require Xcel to make a compliance filing once the Mankato II in-service date becomes certain. If the in-service date does not materialize by 2019, the compliance filing should include the delay's 2019 revenue-requirement impact and how the Company proposes to address it.

B. Rate-Case Expense Amortization

Xcel proposed to amortize the anticipated $3.34 million cost of this rate case over the term of the Settlement. Because most of the parties agreed to a settlement early in the proceeding, the final costs for the case are likely to be lower than initially projected. Accordingly, the Commission will require Xcel to make a compliance filing comparing final Rate Case Expenses to the requested $3.34 million.

C. Sales-Forecast True-up

The 2016 sales-forecast true-up relied on weather-normalized sales data for all customer classes. Similarly, for the partially-decoupled classes, the true-ups in 2017–2019 will also be based on weather-normalized sales. To ascertain the impact of weather normalization on the true-up, the Commission will direct Xcel to include with its yearly true-up filing a true-up calculation based on actual, non-weather-normalized sales and revenue.

CLASS COST OF SERVICE STUDY ISSUES

XIX. Rate Design and Class Cost of Service Introduction

A. Rate Design and Customer Classification

The preceding section established Xcel's revenue requirement for the term of the multiyear rate plan. The following sections will address how Xcel may recover the revenue requirement from its ratepayers. This process of *rate design* requires the Commission to exercise policy judgment because there are many ways to set rates to enable a utility to recover appropriate revenues.

In designing rates, the Commission considers a variety of factors, including:

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[38] *See In the Matter of Draft Purchase Power Agreements with Calpine Corporation and Invenergy Thermal Development, and Proposed Price Terms for Black Dog Unit 6*, Docket No. E-002/M-14-789, Order Approving Power Purchase Agreement with Calpine, Approving Power Purchase Agreement with Geronimo, and Approving Price Terms with Xcel (February 5, 2015).

- Equity, justice, and reasonableness, and avoidance of discrimination, unreasonable preference, and unreasonable prejudice;[39]
- Continuity with prior rates to avoid rate shock;
- Revenue stability;
- Economic efficiency;
- Encouragement of energy conservation;[40]
- Customers' ability to pay;[41]
- Ease of understanding and administration; and, in particular,
- Cost of service.

Estimating the cost to serve any given customer is challenging because a utility will incur different costs to serve different customers, and will incur many costs that benefit multiple customers. Because similar types of customers tend to impose similar types of costs on the system, utilities simplify their analysis by first dividing customers into classes—for example, distinguishing residential customers from commercial or industrial customers. Utilities then attempt to determine the amount of revenues they should recover from each customer class.

To aid this analysis, the Commission directs utilities to conduct a class-cost-of-service study (CCOSS). Minn. R. 7825.4300(C) directs a utility to file

> A cost-of-service study by customer class of service, by geographic area, or other categorization as deemed appropriate for the change in rates requested, showing revenues, costs, and profitability for each class of service, geographic area, or other appropriate category, identifying the procedures and underlying rationale for cost and revenue allocations.

B. Class-Cost-of-Service Studies

According to the *Electric Utility Cost Allocation Manual* of the National Association of Regulatory Utility Commissioners (NARUC Manual), performing a CCOSS involves three steps. First, costs are grouped according to their function (generation/production, transmission, distribution, customer service/facilities, administrative). Second, costs are classified based on how they are incurred. Third, costs are allocated to the various customer classes.[42]

Functionalization: In this case, the two functions that generated the most dispute are generation and distribution.

Generation refers to the cost of plant used to generate electricity.

[39] Minn. Stat. §§ 216B.01, .03.

[40] Minn. Stat. §§ 216B.03, .2401, 216C.05.

[41] Minn. Stat. § 216B.16, subd. 15.

[42] Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, at 18–23 (January 1992).

The distribution system carries electricity from the transmission system to a customer's location. Utilities distinguish between the primary distribution system and the secondary distribution system. In the primary distribution system, electricity travels from the high-voltage transmission system to substations, which reduce the voltage and distribute it via lines and poles to the neighborhoods of retail customers. While some large industrial customers purchase power at primary distribution voltages, generally this electricity flows to the secondary distribution system, where distribution transformers again reduce the voltage, permitting it to be distributed via lines and poles to customer premises.

Classification: The cost of a function might be classified as related to *energy*, *demand*, or *customers*. Energy-related costs increase as customers' consumption of energy increases. Demand-related costs increase as the rate at which customers consume energy increases, especially during periods of peak demand. Customer-related costs increase as the number of customer accounts increases. According to the NARUC Manual, the cost of an electric utility's distribution system is related to energy, demand, and customers.

Allocation: The various costs then get allocated to each customer class. For purposes of its CCOSS, Xcel divides its customers into four classes:

- Residential
- Commercial, without Demand Meters (Non-Demand)
- Commercial & Industrial, with Demand Meters (Demand)
- Street & Outdoor Lighting

For commercial and industrial customers with a demand meter, Xcel calculates a charge for the cost of the facilities required to serve that customer's peak usage (a "demand charge"), as well as a separate charge for the amount of energy consumed. For customers in the other customer classes, the costs of energy and demand are recovered through a per-kWh charge.

The manner in which a CCOSS characterizes costs influences how the study will assign responsibility for raising revenues among the customer classes. For example, because the great majority of Xcel's customers are residential customers, a choice to characterize a cost as a customer cost will result in residential customers bearing the great majority of those costs.

C. Multiyear Rate Case

Because Xcel filed a multiyear rate case, its CCOSS calculated a new estimate of costs attributable to each customer class for 2016, 2017, and 2018.

XX. CCOSS—Classifying Fixed Production Plant

A. Introduction

As noted above, cost classification requires a utility to determine whether a cost varies as the number of customers increases, or as the amount of energy consumed increases, or as the maximum rate of consumption increases. No party disputes that the cost Xcel bears for production plant is driven by the level of demand for electricity; Xcel designs its system to be able to meet the anticipated peak level of demand, and maintain a specified amount of additional generating capacity (known as a reserve margin) to address unanticipated levels of demand or equipment failures. But parties disagree about the extent to which production-plant costs also reflect energy costs.

B. Positions of the Parties

The Chamber proposed classifying production plant costs using the Peak Responsibility Method. The Chamber reasoned that Xcel's investment in production plant is a fixed cost that cannot vary based on how much energy customers consume. Only variable costs, such as the cost of fuel, should be classified based on energy consumption, the Chamber argued; the fixed costs should be classified as demand costs, to be allocated to customer classes in proportion to each class's consumption during the period of peak demand.

In support of its argument, the Chamber noted that its Peak Responsibility Method for classifying fixed projection plant is included in the NARUC Manual. Even if the Commission were not inclined to rely solely on this method, the Chamber argued that it should consider this method along with any other method the Commission chooses.

In contrast, Xcel proposed using its Stratification Method, a variant of the Equivalent Peaker Method set forth in the NARUC Manual, which Xcel has employed since the 1970s. Xcel acknowledged that it selected its portfolio of generators to meet its anticipated peak demand and reserve margins. But Xcel observed that if it were to design a system solely to serve that function, it might have built its entire system out of natural gas "peaking" generators, which have the lowest capital cost per unit of generation. Yet these generators also have high operating costs per unit of energy generated. According to Xcel, the fact that it (and other electric utilities) chose to rely on a variety of generators—including generators with higher capital and lower operating costs—demonstrates that utilities design their systems based on factors beyond meeting peak demand.

Because some share of the capital costs are incurred not to acquire additional generating capacity, but to reduce energy costs, Xcel argued that this share of capital cost should be treated as energy-related costs. Xcel's Stratification Method includes a formula for determining the appropriate share of capital costs to regard as energy costs.

Xcel did not support adopting multiple classification methods, but conceded that the rationale for adopting multiple methods for distribution plant would also support adopting multiple classification methods for fixed production plant.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge noted that the Commission has consistently approved the Stratification method for classifying fixed production plant, and that the matter was sufficiently well established that no party chose to file direct testimony supporting any other theory. The Chamber filed its alternative proposal only in surrebuttal testimony when no party would have the opportunity to file responsive testimony. Because the Chamber's proposal was insufficiently developed in the record, the Administrative Law Judge recommended that the Commission reject it.

D. Commission Action

The Commission concurs with the Administrative Law Judge. The Commission has long recognized that the cost Xcel incurs for its fixed production plant is driven not only by the need to meet peak demand, but also by the need to manage energy costs (including environmental costs). Even the Chamber acknowledged this fact.

The Chamber's proposal, whatever its merits, arose too late in the proceedings to justify consideration here. Consequently the Commission will continue its reliance on the Stratification Method.

XXI. CCOSS—Classifying Distribution Plant

A. Introduction

Parties disagreed about the most appropriate method for classifying the cost of distribution plant.

According to the NARUC Manual, the cost of an electric utility's distribution system is related to energy, demand, and customers.[43] Yet the two methods that the Manual identifies for allocating such costs—the Minimum System Method and the Zero Intercept Method, discussed below—classify the cost of distribution plant as related to demand and customers, and do not classify any part of the distribution system as related to energy.

B. Positions of the Parties

Parties proposed six different methods for classifying distribution costs. Xcel employed the *Minimum System Method* and a variant, the *Zero Intercept Method*, and later combined them to form its *Hybrid Method*. The OAG employed the *Basic Customer Method* and the *Peak-and-Average Method*. Finally, the Chamber proposed relying in part on the *Customer-Related Method*.

1. The Minimum System Method

First, Xcel classified its distribution plant costs using the Minimum System Method. This method reflects the premise that distribution costs should be divided between customer-related costs and demand-related costs, because a utility builds out its distribution plant in order to (a) serve each customer regardless of the amount of demand that each customer puts on the system, and (b) have sufficient capacity to reliably meet customers' peak demand. To use this method, an analyst estimates the cost to build a system that could provide each of Xcel's customers with some minimal level of service. The cost of this minimum system would reflect customer-related costs; any additional costs would be assumed to relate to the need to build capacity to deliver more than just a minimal level of service—that is, demand-related costs.

The Chamber, the Commercial Group, the Department, and XLI generally found this classification method to be reasonable. However, the Department argued that Xcel could improve upon this CCOSS by incorporating data from additional years, and by adjusting its booked cost data to account for inflation.

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[43] NARUC Manual, at 21–22.

The CEO and the OAG criticized Xcel's reliance on this classification method. First, they questioned the choice to divide distribution costs between demand-related costs and customer-related costs, without considering other possibilities such as energy-related costs. For example, the OAG argued that Xcel incurs certain distribution costs for the purpose of reducing energy losses, and that such costs should be regarded as energy-related. The CEO and OAG argued that this foundational defect in Xcel's CCOSS led to results that exaggerate the customer-related costs for distribution plant. The CEO went further, arguing that this initial bias supported mistaken conclusions about the minimum cost to serve a customer, and thus would inflate the costs that Xcel would eventually propose to be borne by low-usage residential customers.

The OAG raised additional concerns about Xcel's proposal. Generally, the OAG argued that the cost of some minimally sized system reaching all customers would reflect more than just the number of customers: it would also reflect customer density, terrain, reliability and quality standards, and other factors. The OAG argued that Xcel's Minimum System Method analysis relied on a variety of arbitrary or questionable assumptions. And the OAG also questioned whether the cost data reflected booked costs, installed costs, or current costs. The net effect of these errors, the OAG alleged, was to generate estimates that exaggerated customer-related costs.

2. The Zero Intercept Method

Second, Xcel classified its distribution plant costs using the Zero Intercept Method. This method also calculates customer-related costs based on the cost of a minimum distribution system. But while the Minimum System Method calculates customer costs in a manner that reflects some level of service capacity—that is, some demand-related costs—the Zero Intercept Method does not. Instead, recognizing that the cost of distribution plant increases as its capacity increases, the Zero Intercept Method uses a mathematical model to project this pattern backwards to estimate the cost of a hypothetical distribution system that would have precisely zero capacity.

Again the Chamber, the Department, and XLI generally found this classification method to be reasonable, and again the Department proposed technical changes for future CCOSSs. The Department found one instance in which Xcel's analysis (regarding underground transformers) may have violated the requirements of the underlying mathematical model, but this did not alter the Department's support for the method.

Again, the CEO and the OAG disputed the merits of classifying costs into demand-related costs and customer-related costs, without considering energy-related costs. In addition, the OAG argued that Xcel's Zero Intercept Method analysis relied on biased data, and insufficient data to support the results of the method's mathematical model.

3. The Hybrid Method

Ultimately Xcel did not recommend that the Commission adopt either its Minimum System Method or its Zero Intercept Method to classify distribution costs. Instead, Xcel proposed incorporating the two into a third method, its Hybrid Method. Xcel divided its distribution plant into functional categories, and then used the previous two classification methods to estimate the share of customer-related costs in each category. Where these two methods disagreed, Xcel would pick the smaller of the two estimates of customer-related cost. The remaining share of costs in each category would be assumed to be demand-related costs.

In support of this choice, Xcel argued that both the Minimum System Method and the Zero Intercept Method were designed to identify the cost of some minimally sized distribution plant necessary to reach all customers, and to characterize only that cost as customer-related. Xcel found both models reasonable, and reasoned that by picking the lowest allocation attributed to customer costs, Xcel could best fulfill the models' objectives.

Again the Chamber and the Department generally found this classification method to be reasonable, and again the Department proposed technical changes for future CCOSSs. But while XLI supported both the Minimum System and Zero Intercept Methods, it opposed the Hybrid Method. XLI argued that the Hybrid Method, by picking data from the other two methods based solely on the criterion of minimizing customer costs, was structurally biased to inflate demand costs—which would ultimately have the effect of increasing rates for the Commercial & Industrial Demand class and the Lighting class.

Because the Hybrid Method incorporates both of the previous two methods, the CEOs' and the OAG's objections to those earlier methods also applied to the Hybrid Method. Acknowledging that all classification methods are imperfect, however, the OAG did not ask the Commission to reject this method entirely. Instead, the OAG asked the Commission to consider this method along with two other classification formulas: the Basic Customer Method and the Peak-and-Average Method, discussed below. In support of its position, the OAG cited prior Commission decisions directing utilities to consider multiple CCOSS models.

4. The Basic Customer Method

Similar to the previously discussed classification methods, the Basic Customer Method begins by attempting to identify the subpart of distribution costs that should be characterized as customer-related costs, and assumes that any excess cost should be attributed to demand. But while the Minimum System Method calculates customer-related costs based on the cost of a minimum distribution system, the Basic Customer Method includes only costs that can be attributed to individual customers—such as the costs of meters, billing, and collection—and treats the remaining shared costs as related to demand. Compared to the Minimum System Method, the Basic Customer Method classifies less cost as customer-related, and more cost as demand-related.

In support of the Basic Customer Method, the OAG reasoned that distribution plant that serves more than one customer is shared plant, and that Xcel designed its distribution system to have sufficient capacity to maintain service during periods of peak demand, rendering most of these shared costs demand-related costs. The OAG also cited academic studies and decisions from other jurisdictions supporting the use of the Basic Customer Method.

The Chamber, the Department, Xcel, and XLI opposed the Basic Customer Method, arguing that this formula would fail to classify costs based on cost causation and would be inconsistent with many prior Commission orders. The Chamber expressed concern that this method would allocate excessive costs to Xcel's commercial and industrial customers, making their operations uncompetitive with firms operating in an environment with cheaper electricity.

5. The Peak-and-Average Method

The previously discussed classification methods anticipate that demand-related costs will be allocated among customer classes based on each class's share of energy consumption during the period of peak demand. These methods reflect the idea that a utility designs and builds its system to have sufficient capacity to meet the needs of all its firm customers during periods of peak demand, no matter how brief that period is. In practice, this dynamic causes residential consumers to bear a share of the utility's costs that is larger than the share of energy that residential customers consume.

In contrast, the Peak-and-Average Method proposes to support a cost allocation that reflects not only usage during the rare peak periods, but also usage during the average periods. Similar to the Basic Customer Method, this method identifies a narrow range of customer-specific costs—generally, the cost of customer meters and service drop lines—and identifies a share of the remainder as demand-related costs to be allocated based on each customer class's energy consumption during periods of peak demand. But the Peak-and-Average Method also identifies a share of costs to be allocated based on each class's average demand—in effect, based on the class's share of total energy consumed. This has the effect of assigning less distribution-system cost to residential customers, and more to industrial customers.

In support of its proposal, the OAG noted that the NARUC Manual includes the Peak-and-Average Method among its approved classification methods—although the manual approves this method for classifying production costs, not distribution costs.

The Chamber, the Department, Xcel, and XLI reiterated the objections that they raised with regard to the Basic Customer Method, emphasizing their claim that this method fails to classify cost based on cost causation. They argued that Xcel must build its distribution plant to reliably serve customers during periods of peak demand—making these costs demand-related costs. Because Xcel incurs little additional distribution-plant cost to serve customers during average periods, these parties disputed the merits of classifying costs on this basis. Xcel reported that it could not identify any jurisdiction that had adopted this method for allocating distribution plant.

6. The Customer-Related Method

Finally, if the Commission adopts any or all of the OAG's CCOSS methods, the Chamber would ask the Commission to also adopt its Customer-Related Method. This method reflects the premise that the cost of Xcel's distribution plant increases as the number of Xcel's customers increases, and thus would allocate distribution costs among customer classes in proportion to the number of customers in each class. This method would allocate more costs to the residential class than any other allocation method in the record.

The OAG opposed this method, arguing that it lacked any plausible relationship to cost causation.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the Minimum System Method, the Zero Intercept Method, and the Basic Customer Method were imperfect but reasonable means for allocating the cost of the distribution plant. But because Xcel's Hybrid Method would act to mitigate the imperfections in the Minimum System and Zero Intercept methods, the ALJ found that method to be the most reasonable allocation method in the record.

The ALJ noted that the NARUC Manual, in setting forth allocation methods for distribution plant, discusses only the Minimum System and Zero Intercept methods. The Commission has long favored using one or both of these methods for allocating distribution costs—as have the regulatory commissions in neighboring states. Moreover, the Commission has refined Xcel's CCOSS over the years to make it more transparent. The ALJ found that the parties who filed testimony on CCOSS all conceded the merits of the Minimum System Method or Zero Intercept Method or both.

The ALJ acknowledged that the Basic Customer Method had the advantage of simplicity, but found that this method inappropriately characterized certain customer-related costs as demand-related.

The ALJ noted that XLI argued that Xcel's Hybrid Method reflected an undue bias in favor of lower cost for residential customers. But the ALJ concluded that the Hybrid Method was designed to guard against overstating customer costs, and so Xcel was justified in taking such precautions.

The ALJ rejected the Customer Related Method (with its emphasis on customer-related costs) and the Peak-and-Average Method (with its emphasis on energy-related costs) for failing to give sufficient weight to the fact that electric utilities design their systems to meet peak demand. The ALJ concluded that these two methods generated extreme—and generally offsetting—allocation results.

The ALJ gave special attention to the role of energy-related costs in the distribution system. The NARUC Manual makes passing reference to distribution plant reflecting energy-related costs, but also explicitly denies that distribution plant reflects energy-related costs. In any event, the only allocation methods listed in the manual for distribution plant divide the costs into two categories—customer-related costs and demand-related costs—with no component characterized as energy-related. While the OAG argued that utilities design their distribution systems to reduce the amount of energy lost, the record reveals that line losses in the distribution system are less than eight percent. The ALJ found that this fact undermined the credibility of the Peak-and-Average Method, which characterizes most distribution costs as energy-related.

D. Commission Action

While the parties have rigorously argued and disputed the best method for allocating distribution costs, they all concurred with the ALJ in this: Cost models are imperfect. They build a simplified model of a utility's system, and use the model to draw conclusions allocating costs into functional categories to help inform the Commission's eventual allocation of joint costs among customer classes.

Thus, for example, the OAG correctly observed that the cost to serve a population of customers will vary depending not only on the number of customers, but on their dispersion, the terrain in which they live, and many other variables. Nevertheless, when a utility serves a large population, it is not unreasonable to expect a cost model to identify costs that correlate with the number of customers served, and the average magnitude of those costs per customer. Because the Commission will ultimately establish uniform rates within each customer class—rates that will not vary based on the type of terrain surrounding a customer's premises, for example—adding this level of precision to a cost model may cause burdens without any corresponding benefits.

Xcel and the Department recommended that the Commission rely on Xcel's Hybrid Method, which is a combination of two other methods. Similarly, the OAG urged the Commission to consider still other allocation methods. And the ALJ acknowledged that the Commission may wish to give credence to multiple methods, noting that Xcel's Hybrid Method may understate demand-related costs while the Basic Customer Method would overstate these costs. All of this is consistent with the NARUC Manual's conclusion that no single cost-study method can be judged superior to all others in all contexts. For these reasons, the Commission will consider a range of classification methods for purposes of allocating responsibility for the necessary revenues among Xcel's various customer classes.

Anticipating this outcome, the ALJ recommended that the Commission state how much weight it would give to the results of each functionalization method in Xcel's next rate case. But one term of Xcel's settlement in this proceeding is that Xcel would refrain from seeking a general rate increase for the next four years. The Commission is disinclined to impose this degree of precision on the kind of cost study Xcel may find appropriate four years hence. It will suffice to say that by providing multiple methods for functionalizing costs, parties provide a range of guidance upon which the Commission may rely in allocating costs among Xcel's customer classes.

XXII. CCOSS—Calculation of D10S Allocator

A. Introduction

As previously discussed, a CCOSS classifies certain investments as related to demand. No party disputed that these investments would be allocated among the customer classes in proportion to each class's energy consumption during periods of peak demand. But parties disagreed about what constitutes the relevant period of peak demand.

Historically electric utilities operated independently, building their own plant to generate, transmit, and distribute electricity to their own customers. These utilities designed their system to be able to meet their customers' needs during periods of peak demand, plus maintain a margin of capacity to manage unanticipated circumstances (extra demand, or unplanned outages from a generator or transmission line).

But today many electric utilities join together to form independent system operators such as MISO. Through MISO's wholesale energy markets, utilities benefit from the use of each other's facilities. This does not mean that utilities no longer need to make arrangements to serve their peak load, or to maintain a reserve margin. But a utility may anticipate relying on the regional power system to help meet the utility's needs.

MISO establishes the required amount of reserve capacity, and allocates the responsibility for meeting this obligation among load-serving entities such as electric utilities. Finally, MISO calculates this reserve margin based on peak demand for the relevant MISO Zone—which may not coincide with the peak demand on any individual utility's network.

For Xcel, these two peak demands do not coincide. The 2016 period of peak demand for MISO Local Resource Zone 1 (which includes Xcel's service area in Minnesota) occurred on July 14 at 3:00 p.m.[44] But the 2016 period of peak demand for Xcel's system occurred two weeks later, on July 28 at 4:00 p.m. More significant than the difference in time is the difference in usage patterns during the two peaks. Specifically, during the MISO peak, commercial and industrial customers were consuming a larger share of total energy than during the Xcel peak, while

[44] The MISO Peak D10S Allocator is based on the hour of highest demand in MISO's Local Resource Zone-1, which encompasses most of Minnesota, all of North Dakota, and portions of Montana, South Dakota, and Wisconsin. *See* http://www.misomtep.org/independent-local-forecasting/.

residential customers followed the opposite pattern. Thus, the choice between methods for measuring demand will have foreseeable consequences for different customer classes.

B. Positions of the Parties

In compliance with a Commission directive from Xcel's last rate case, Xcel calculated its measure of demand—which Xcel labels the *D10S Allocator*—for both a MISO peak and an Xcel peak.

Xcel initially favored reliance on the MISO Zonal peak for purposes of allocating demand-related costs among customer classes. But after considering the positions of the Chamber, the Department, the ICI Group, and XLI, Xcel switched its position and began arguing for using its own system peak as the measure for D10S.

Xcel argued that it designs its system to meet the peak demand that its customers impose on Xcel's system. In contrast, Xcel argued that a D10S Allocator developed on the basis of MISO's Zonal peak hour would not accurately reflect the factors that cause Xcel to incur additional capacity costs.

The Chamber, the Department, the ICI Group, and XLI supported Xcel's position.

In contrast, the OAG supported using the MISO system peak. The OAG reasoned that Xcel must have extra generation available to provide the capacity reserve margin that MISO mandates. The OAG argued that many of the primary decisions that drive Xcel's resource planning—and, therefore, cost causation—are made at the MISO level.

C. The Recommendation of the Administrative Law Judge

The ALJ concurred with Xcel. The ALJ found that Xcel designs its plant to meet the peak demand of its own customers on its own system, and therefore Xcel's D10S Allocator should reflect this fact. The ALJ also expressed concern about the variability in the D10S allocator based on MISO's Zonal peak.

D. Commission Action

At one time, Xcel's primary focus for system design was doubtless on the peak demand for its system. But now that Xcel is a member of MISO, Xcel must meet the reserve requirements established by that organization.

While Xcel and other parties persuaded the ALJ that Xcel designs its system to meet its own system peak, the Commission notes that MISO prescribes the formula for calculating the amount of capacity that any given member is to maintain. And those reserve requirements are designed to meet the peak load of the MISO Zone. While calculating the D10S Allocator on the basis of the MISO Zonal peak may generate allocations that change over time, the same is true of an allocator based on Xcel's own system peak.

Prospectively, therefore, the Commission will direct Xcel to base the D10S capacity allocator on Xcel's system peak coincident with MISO's system peak. And given that MISO is expecting to change its own formula for allocating costs during peak demand, the Commission will also direct Xcel to incorporate into its next rate case any changes that MISO adopts.

XXIII. CCOSS—D60Sub Capacity Allocator

A. Introduction

In electricity transmission and distribution, substations provide a means for converting high-voltage electrical current to low-voltage current, and vice versa. While most substations serve the transmission/distribution grid as a whole, a utility may build a substation purely to serve one or more large industrial consumers.

Xcel uses its D60Sub Capacity Allocator to recover the cost of substations from among all its customers—unless those substations serve a specific customer. In that case, those costs are directly assigned to the specific customer.[45]

But if a large industrial customer is already bearing the directly assigned costs of its own substation or substations, should that customer also have to bear a share of the cost of the other substations? The parties disagreed.

B. Positions of the Parties

According to the Department, all customers benefit from the transmission and distribution systems, which includes substations, and so all customers should bear a share of these substation costs. The fact that a customer bears the directly assigned cost of one or more substations should not excuse that customer from also bearing a fair share of the allocated costs, the Department argued.

Xcel, the OAG, and XLI disagreed. They acknowledged that all customers should bear a portion of the cost of, say, the transmission system. But where a customer is served from a designated substation—and already bears the cost of that substation—these parties agreed that it would not be appropriate to ask that customer to also bear a share of the cost of substations that do not serve the customer.

C. The Recommendation of the Administrative Law Judge

The ALJ agreed with the majority of parties that a customer who receives service via a specific substation, and bears the direct cost of that substation, need not bear the additional cost of substations from which the customer derives no benefit.

D. Commission Action

The Commission concurs: If a party is directly assigned the cost of a substation, and receives service via that substation to the exclusion of all the other substations, then the party should be excused from bearing a share of the cost of the substations that do not serve the customer. The Commission will direct Xcel to incorporate this change into its CCOSSs in future rate cases.

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[45] I*n the Matter of an Investigation into the Competitive Impact of Appliance Sales and Service Practices of Minn. Gas and Electric Utilities*, Docket No. G,E-99/CI-90-1008, Order Setting Filing Requirements (September 28, 1994) at 4-6, as modified by Order Clarifying Commission Order Dated September 28, 1994 (March 7, 1995) (collectively, Cost Allocation Order).

XXIV. CCOSS—Allocation of the Cost of Stranded Facilities

A. Introduction

Where Xcel builds a facility for the benefit of a member of the Commercial & Industrial class, it directly assigns to that customer the cost of that facility. But when the customer ceases to take service from Xcel, should Xcel allocate the cost to the other members of the Commercial and Industrial class? Or should the costs be shared among all customer classes, as just one more general cost that utility incurs? The parties disagreed on how to resolve this issue.

B. Positions of the Parties

The Department cites the Commission's Cost Allocation Order for the proposition that, where a cost cannot be directly assigned, it becomes a common cost to be allocated based on an analysis of the cost's origins or, barring that, based on a similar cost category.[46] The Department reasons that, barring an opportunity to recover the cost of an asset from the Commercial/Industrial customer who directly caused Xcel to incur the cost, the second-best proposal is to recover the costs from the same customer class. But the Department acknowledged that if a facility could be repurposed, an appropriate share of the facility's cost should be allocated in accordance with the new purpose.

According to XLI, the cost of a stranded facility is simply a cost of doing business for a regulated utility. XLI argued that there was no more reason to assign the cost of one Commercial & Industrial customer to other Commercial & Industrial customers than to Residential or Lighting customers.

Xcel concurred with XLI.

C. The Recommendation of the Administrative Law Judge

The ALJ was persuaded by the Department that the Commission's prior findings regarding cost allocation govern this question, and that costs that originated within a Commercial & Industrial class should be recovered from that class.

D. Commission Action

The Commission concurs. As the Commission's Cost Allocation Order illustrates, cost recovery is an inexact science. As noted in the Commission's Cost Allocation Order, the Commission favors assigning costs directly where possible, assigning costs indirectly where not, and treating expenditures as general overhead costs as a last resort.[47]

Here, Xcel has built facilities to serve specific Commercial & Industrial customers, some of whom no longer take service from Xcel. These costs were caused by the customers requesting the facilities—but also by Xcel's policy of accommodating certain kinds of requests from large customers. This policy arguably benefits the Commercial & Industrial classes generally—and the costs of the policy should accrue to those who benefit most proximately.

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[46] Cost Allocation Order, at 4–6.

[47] *Id*.

XXV. CCOSS—Allocation of Line Losses

A. Introduction

The amount of electricity Xcel generates exceeds the amount it delivers to retail customers because some amount of energy is lost though the process of transmission and distribution. Line loss is an inevitable cost of operating an electric utility, and Xcel recovers that cost from ratepayers generally.

But arguably Xcel incurs more of these costs in serving some customers than others. This is because line losses do not occur uniformly; certain factors lead to higher line losses—and these factors are arguably associated with serving the Residential class.

For example, line losses increase as voltage decreases. Thus, a single large industrial customer may buy as many kWh as a neighborhood of residential customers—but if the large customer receives the electricity at a higher voltage, Xcel will incur less line loss in delivering those kWhs than when delivering the same total energy to residential customers at a lower voltage.

Also, line losses increase during periods of peak demand, as lines become hot and congested. Large commercial and industrial customers tend to consume energy at a more uniform rate over time; lighting customers consume energy off-peak; but residential customers tend to consume a disproportionate share of energy during peak hours. Thus it is plausible that Xcel incurs a disproportionate share of its line losses serving residential customers.

The parties disagree about whether Xcel must incorporate these dynamics into its CCOSS.

B. Positions of the Parties

XLI argued that principles of cost causation should compel Xcel to incorporate line-loss dynamics into its CCOSS. Otherwise, the Commercial & Industrial classes would subsidize other customer classes—especially the Residential class.

Both Xcel and the Department stated that they were willing to consider the idea, but found that it was unclear whether Xcel had the necessary data to conduct the relevant analyses. The Department noted the possibility that the cost of adding this level of precision might exceed its benefits. But Xcel expressed a willingness to explore the issue in its next rate case.

C. The Recommendation of the Administrative Law Judge

The ALJ concluded that XLI's proposal was theoretically sound, uncontested, and worthy of consideration—in Xcel's next rate case. Thus the ALJ recommended that the Commission direct Xcel to report on methods to conduct line-loss studies to develop a more accurate measure of line losses in the future. The ALJ specifically proposed that Xcel treat line losses as an energy-related cost.

D. Commission Action

The Commission concurs with the parties that consideration of line losses may further enhance the accuracy of CCOSSs. As a result, the Commission will adopt the ALJ's recommendation to direct Xcel to report on methods to conduct loss studies to measure these losses.

That said, at this early stage the Commission will decline to constrain Xcel's choice to treat line losses as energy-related, demand-related, both, or neither. The design of the studies will be a matter for all participants to explore together.

XXVI. CCOSS—Allocation of the Cost of the Renewable Development Fund

A. Introduction

The Minnesota Legislature created the Renewable Development Fund (RDF) by statute to promote renewable electric energy resources and projects and to assist companies in the renewable electric energy industry.[48] The statute directs the owner of the Prairie Island and Monticello nuclear generating plants—that is, Xcel—to finance the fund based on the number of dry casks containing spent fuel that Xcel stores by the plants.

Parties disagreed about the appropriate means to allocate the cost of fund contributions and administration among Xcel's customer classes.

B. Positions of the Parties

The Chamber objected to Xcel's practice of allocating RDF costs to classes in proportion to each class's energy consumption. Concluding that research and development was no more likely to be energy-related than demand-related, the Chamber proposed allocating only half of these costs based on each class's cost-weighted energy consumption (the E8760 Allocator), and half based on demand (the D10S Allocator).

The OAG argued that the Chamber's proposal, whatever its merits, would not create more than a 0.01 percent change in cost allocations to the Commercial & Industrial Demand class. On this basis, the OAG recommended foregoing this change.

The Department and Xcel also opposed the Chamber's proposal on the grounds that the matter could be more appropriately addressed in any of Xcel's regular dockets specifically addressing the RDF. The Chamber found this proposal acceptable.

C. The Recommendation of the Administrative Law Judge

The ALJ rejected the Chamber's proposal for lacking sufficient foundation in the record. The ALJ concluded that Xcel's RDF costs were neither energy-related nor demand-related, but were Legislature-related; accordingly, the ALJ could find no merit in the Chamber's proposal.

D. Commission Action

Because the matter raised by the Chamber has been insufficiently developed, the Commission will decline to render a decision one way or another, other than to concur with the consensus that this matter need not be addressed in this docket.

Likewise, the Commission will decline to expressly assign this issue to Xcel's next RDF Rider docket. Interested parties should feel free to raise this matter on their own initiative, if they wish.

[48] Minn. Stat. § 116C.779

XXVII. CCOSS—Allocation of the Cost of Conservation Improvement Programs

A. Introduction

The Legislature has also created the Conservation Improvement Program (CIP). CIP encompasses most of the state's energy-conservation and energy-efficiency initiatives, from energy audits and appliance rebates to energy-efficient construction guidelines and manufacturing process improvements. CIP costs are recovered through the Conservation Cost Recovery Charge (CCRC) and the CIP Rider. The CCRC is recovered via a utility's base rates, while CIP Rider costs are recovered via a per-kWh charge that is included in the Resource Adjustment on customers' bills.

Approximately $89 million of CIP costs are recovered through base rates and $40 million through the rider. The usage of CIP-exempt customers (certain commercial and industrial customers) is excluded from the allocator.

Parties disagreed about whether to allocate these costs based on simple energy sales, or based on cost-weighted energy sales (the E8760 Allocator).

B. Positions of the Parties

Xcel allocated both the CCRC and the CIP Adjustment Factor (CAF) on the basis of energy consumption. Specifically, CCRC costs were allocated to customer classes using the 2016 test-year sales forecast after subtracting sales to CIP-exempt customers.

The Chamber proposed that the CIP CCRC costs be allocated using the percent-of-benefits method. The percent-of-benefits method is intended to reflect the cost allocations that would result from the supply-side investments that CIP expenditures permit a utility to forgo.

As an alternative, the Chamber suggested that if the Commission intends to allocate conservation costs based on energy sales, the Commission should adopt the E8760 Allocator that excludes CIP-exempt customers. Because the E8760 Allocator links hourly marginal prices to hourly customer loads, the Chamber argued, it provides a more accurate pricing signal for CIP-related initiatives. The Chamber showed that using the E8760 Allocator after excluding CIP-exempt customers resulted in shifting costs away from the Street Lighting and C&I Demand class and onto the Residential and C&I Non-Demand classes.

The OAG opposed changing the allocator, arguing that the goal of CIP was to reduce kWh sales, not marginal energy costs.

But Xcel, the Chamber, the Department, and XLI all supported the idea of evaluating the use of the E8760 Allocator, with CIP-exempt usage excluded, in Xcel's next CIP Rider proceeding.

C. The Recommendation of the Administrative Law Judge

The ALJ concluded that the record provided insufficient information about the Chamber's proposal, and the Legislature's goals for CIP, to justify adopting it. The ALJ suggested that parties might choose to take up this matter in a CIP rider docket.

D. Commission Action

As with the Chamber's proposal for changing how CCOSSs deal with the Renewable Development Fund, the Commission finds that the proposal for changing how CCOSSs allocate CIP expenditures is insufficiently developed. As the OAG observed, it is far from clear that CIP costs should be allocated based on the E8760 Allocator rather than simply based on energy sales.

Again, while the Commission will decline to refer this matter to Xcel's next CIP Rider docket, interested parties should feel free to raise this matter on their own initiative, as they wish.

XXVIII. CCOSS—Allocation of the Cost of Solar Power Purchase Agreements

A. Introduction

Presently, power purchase agreements (PPAs) for electricity generated by the sun are recovered through the fuel clause adjustment (FCA) using the E8760 allocator; all these costs are characterized as energy-related.

Yet MISO recognizes that solar generators provide not only energy, but also generating capacity. This is because solar generators generate fairly reliably during periods of peak demand, which typically occur in the afternoon. Specifically, MISO has a default assumption that solar-powered generators have an accredited capacity of half of their nameplate level of generation (recognizing that solar energy is somewhat reliable, but not as reliable as dispatchable sources of generation such as fossil-fuel-powered generators).

Parties disagreed about whether some portion of the cost of solar PPAs should be characterized as demand-related, and allocated according to the D10S Allocator.

B. Positions of the Parties

The Chamber argued that only half of the cost of a solar PPA should be allocated based on energy, and the other half should be allocated based on demand (the D10S Allocator).

The Department found the Chamber's proposal to be reasonable for recovering the cost of solar PPAs that have been embedded in base rates.

But Xcel and the OAG opposed the Chamber's proposal. The OAG argued that the record did not support changing the Commission's long-standing treatment of solar PPAs as energy-related, and the long-standing practice of allocating the costs based on the E8760 allocator.

C. The Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission not rely on MISO's default policy of crediting half of a solar generator's nameplate generating capacity, on the theory that the dynamics that apply to MISO's system are not the same as the dynamics that apply to Xcel's system. This echoed the ALJ's reasoning leading to the conclusion that Xcel should calculate its D10S Allocator based on Xcel's system peak, not the MISO Zone's peak.

The ALJ emphasized that this recommendation reflected the current state of the record, and that a different decision might be warranted in a future proceeding.

D. Commission Action

Again, the Commission is not persuaded of the need to continue calculating Xcel's D10S Allocator based on Xcel's system peak, without regard to MISO's peak. But the Commission concurs that the merits of re-allocating the cost of solar PPAs have received insufficient attention in this proceeding to warrant adoption. For this reason, the Commission will adopt the ALJ's recommendation and decline to direct Xcel to make this change in future CCOSSs.

RATE DESIGN ISSUES

XXIX. Interclass Revenue Apportionment

A. Introduction

As previously noted, after the Commission establishes a utility's revenue requirement, the Commission must design rates that will provide the utility with a reasonable opportunity to recover these costs. The next step in that process is to establish the share of Xcel's revenue requirement to be recovered from each class of customers served by the utility. In making this apportionment, the Commission considers the totality of the evidence in the record, and especially the costs that the utility incurs to serve each customer class (as established by CCOSSs).

B. Positions of the Parties

Generally, each party identified its favored CCOSS or CCOSSs, discussed above, and recommended apportioning responsibility for Xcel's revenue requirement in a manner that would cause each customer class to approach bearing the full costs indicated by the favored CCOSS. Because Xcel has proposed a multiyear rate plan, parties had the opportunity to propose implementing shifts to the revenue apportionment gradually over four years to mitigate the risk of rate shock. The parties differed in their choice of CCOSS, and in the speed with which rates should transition to achieve the apportionments specified in the CCOSSs.

1. Xcel

Xcel proposed to gradually phase in changes to its interclass apportionments to cause each class to fully bear the costs assigned to it by the Hybrid Model CCOSS by 2019.

Generally Xcel would implement two-thirds of this change by 2017, hold the apportionments uniform for 2018, and transition all the way to cost-based apportionment by 2019. But because Xcel's CCOSS proposes a relatively large increase to the Lighting class, Xcel would propose to limit the increases to this class to no more than ten percent in any given year. As a result, by 2017 the gap between the costs attributed to the Lighting Class and the revenues recovered by that class would decrease by only half, rather than two-thirds.

2. The Commercial Group, XLI, and the Chamber

The Commercial Group, XLI, and the Chamber also supported apportioning Xcel's revenue requirement among customer classes according to the Hybrid Method CCOSS. But they each recommended revising Xcel's cost model to incorporate changes they had proposed, as discussed previously; the Commercial Group supported incorporating the changes proposed by XLI, or whichever changes the Commission approved.

Each party proposed a different schedule for transitioning to an apportionment that matches the CCOSS. The Commercial Group supported Xcel's proposal to begin by apportioning revenues to eliminate two-thirds of the difference between the share of revenues a class generates and the share prescribed by the CCOSS. But unlike Xcel, the following year the Commercial Group would apportion revenues to eliminate two-thirds of the remaining difference, and adopt a fully cost-based apportionment thereafter.

XLI favored a still more aggressive transition, eliminating three-quarters of the difference between revenues raised and the CCOSS in the first year, and gradually eliminating the remainder in subsequent years. And the Chamber favored the most aggressive transition of all, adopting a purely cost-based apportionment immediately.

The only non-cost factor considered by these parties was a concern for commercial and industrial customers bearing the cost of "uncompetitive" rates.

3. The Department

The Department recommended implementing Xcel's proposed apportionment through the year 2018, but not the final reapportionment for 2019. Unlike the prior parties, the Department did not recommend eventually adopting a fully cost-based plan, favoring a policy that provided for consideration of non-cost factors as well.

4. The OAG

The OAG developed its proposed apportionment based on three CCOSSs in the record: the Hybrid Method, the Basic Customer Method, and the Peak-and-Average Method. According to the OAG, this foundation made its apportionment more reasonable and stable than proposals based on only one or two CCOSSs.

The OAG stated that it developed its proposal by seeking out patterns among the studies, including customer classes that all the studies identified as bearing too much revenue responsibility, or bearing too little. The OAG also identified classes that two of the three studies identified as bearing too much cost, or too little. (The Residential Class was among those classes.) The OAG then proposed apportionments to bring each of these classes closer to the apportionments indicated by all or most of the studies.

The OAG criticized apportionment proposals that relied on fewer cost models, or that failed to provide for consideration of non-cost factors required by law or past practice. And the OAG argued that its concerns about placing undue reliance on any one CCOSS was heightened in the context of the Settlement, wherein parties arguably refrained from contesting and refining the cost elements as they otherwise would have.

5. ECC

ECC objected to Xcel's proposed apportionment, claiming that it would impose significant burdens on residential customers, especially low-income customers. According to the most recent data that ECC had obtained from Xcel, more than 41,000 of Xcel's residential customers have electric bills that are more than 60 days past due, and the average amount of these outstanding debts is $473.

Fortunately, ECC reported, many of these customers are eligible for the federal Low Income Home Energy Assistance Program (LIHEAP), which is designed to help them meet their home energy needs.[49] But ECC also reported that in Minnesota, only about 30 percent of customers that meet the income qualifications for LIHEAP assistance actually receive that assistance.

Consequently ECC recommended that the Commission direct Xcel to inform customers with overdue bills about the availability of LIHEAP assistance. And to better monitor the consequences of any rate increase for residential customers, ECC recommended that the Commission direct Xcel to report every six months on the number of customers with past-due bills, the amount of those bills, and the number of customers disconnected.

C. The Recommendation of the Administrative Law Judge

The ALJ ultimately recommended that the Commission adopt an apportionment that would eventually result in each class bearing its share of Xcel's revenue requirement as indicated by a CCOSS. But the ALJ rejected arguments that competitive pressures on commercial and industrial customers required this result, concluding that allegations of competitive harm had not been adequately demonstrated on the record. Moreover, the ALJ noted that the Department—which generally supported Xcel's proposed apportionment—did not join the other parties in declaring the need for each class fully bear the costs assigned to it by a CCOSS, to the exclusion of all other considerations.

The ALJ recommended an apportionment based on Xcel's CCOSS with modifications, to be implemented over four years, but limiting any increase to a customer class to no more than ten percent per year.

D. Commission Action

All parties have made credible proposals for apportioning Xcel's revenue requirement. The three principal proposals are set forth below:

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[49] Under the LIHEAP program in Minnesota, Xcel provides residential customers with a 50 percent discount on their first 300 kWh consumed each month. *See* Campaign for Home Energy Assistance, Minnesota, at http://liheap.org/states/mn/ (last visited Feb. 24, 2017).

	2016 Actual Weatherized-Normal[50]	2016	2017-2018	2019
Xcel Final Proposed Revenue Apportionment				
Residential	36.25%	36.74%	36.97%	37.03%
C&I Non-Demand	3.57%	3.51%	3.51%	3.51%
C&I Demand	59.31%	58.86%	58.61%	58.54%
Lighting	0.87%	0.90%	0.91%	0.91%
TOTAL	100.00%	100.00%	100.00%	100.00%
OAG Final Proposed Revenue Apportionment				
Residential	36.25%	36.03%	35.95%	35.89%
C&I Non-Demand	3.57%	3.51%	3.50%	3.50%
C&I Demand	59.31%	59.56%	59.64%	59.69%
Lighting	0.87%	0.90%	0.91%	0.91%
TOTAL	100.00%	100.00%	100.00%	100.00%
ALJ Final Proposed Revenue Apportionment				
Residential	36.25%	37.27%	37.47%	37.51%
C&I Non-Demand	3.57%	3.44%	3.45%	3.45%
C&I Demand	59.31%	58.39%	58.15%	58.09%
Lighting	0.87%	0.91%	0.93%	0.95%
TOTAL	100.00%	100.00%	100.00%	100.00%

Analysis of the issue of interclass revenue apportionment has been complicated by the fact that parties filed testimony and briefs on the basis of a sales forecast—but actual 2016 sales fell 3.3 percent below forecast, resulting in a shortfall in net present revenue of nearly $60 million.[51]

This degree of variability demonstrates the challenge of establishing interclass revenue apportionments based on anticipated circumstances. Complications involving intraclass revenue apportionments then become compounded as the Commission later establishes the other elements of rate design.

Thus, while a multiyear rate plan provides the flexibility to establish apportionments that change with each year, prudence favors following the Commission's past practices. So as a preliminary matter, the Commission will act on the basis of the CCOSS data currently available in the record, rather than relying on a new and currently unknown study. And the Commission will set rates with the aid of fixed apportionments that will remain in effect until Xcel's next rate case.

With that resolved, the Commission must finally determine the appropriate apportionments for each rate class.

[50] Xcel compliance filing (April 24, 2017).

[51] Xcel Compliance Filing (March 16, 2017).

Each party has presented a plausible theory for apportioning revenue responsibility among classes. The Department and the OAG each developed proposals based on multiple CCOSS methods, acknowledging that no one method provides the best cost allocations for all purposes. And the ALJ found "none of the CCOSSs presented to be sufficiently precise in their measurements" to justify adopting and implementing any study's apportionment immediately.[52]

Having given due consideration to each CCOSS in the record, and having reviewed the parties' proposals, the Commission concludes that the first year of Xcel's proposed apportionment best balances the competing considerations.

Residential	36.74%
C&I Non-Demand	3.51%
C&I Demand	58.86%
Lighting	0.90%

This apportionment has multiple advantages. For each class, Xcel's proposed 2016 apportionment coincides with the OAG's or the ALJ's 2016 recommendations, or falls between the two. This apportionment will substantially reduce the difference between each class's costs and its revenues, which should help alleviate the competitive concerns of the Commercial & Industrial classes. This apportionment will promote rate stability by avoiding annual re-apportionments as proposed by Xcel and the OAG.

In particular, the Commission remains mindful of how rate increases affect residential consumers, especially those with low incomes. While the Commission cannot shield every class from the consequences of a rate increase, the Commission concurs with the ECC that more can be done to ensure that low-income consumers gain access to all assistance that is available to them. Fortunately, Xcel has stated its willingness to do its part. Therefore the Commission will direct Xcel to take three steps to aid customers in finding help, and to disclose the extent of financial problems among residential customers:

First, the Commission will direct Xcel to actively reach out to customers with overdue bills in order to inform them about the availability of assistance from LIHEAP.

Second, the Commission will direct Xcel to make a filing within 120 days of this order containing—

- information regarding the availability of LIHEAP funds available for Xcel's low-income customers,
- data regarding the amount of LIHEAP funding that is not claimed during the year, and
- a plan to improve its outreach to low-income customers.

[52] ALJ's Report ¶ 918.

Third, the Commission will direct Xcel to make a filing every six months disclosing—

- The number of past-due residential customers and arrearage information, and
- The number of residential service disconnections.

Additional efforts, bolstered by additional information, will help mitigate the consequences of the rate increase for Xcel's low-income ratepayers.

XXX. Monthly Customer Charge

A. Introduction

While revenue apportionment focuses on how revenue responsibility should be apportioned *among* customer classes, setting the customer charge addresses how revenues are collected *within* each customer class.

Xcel assesses charges to members of each customer class based on a two- or three-part rate. One part consists of a fixed customer charge that accrues as long as the customer remains a subscriber for Xcel's services. Another part consists of an energy charge that accrues as the customer consumes more energy. And for certain classes of larger customers, Xcel also assesses a monthly demand charge that grows as the customer's peak energy consumption grows.

The forecasted sum of the revenues from a class's customer charge, energy charge, and demand charge must equal the class revenue apportionment. Thus rate design poses a tradeoff: the choice to reduce any one component of these charges must result in an increase to another component. For customers that do not pay a separate demand charge—such as residential customers—an increase in the customer charge will have the effect of reducing the energy charge, and vice versa.

Utilities generally favor increased customer charges to make total bills and revenue collections more stable by reducing the share of a class's revenue requirement to be recovered on the basis of energy consumption, which varies month to month. However, Minnesota Statues section 216B.03 directs the Commission to set rates to encourage energy conservation and renewable energy use "to the maximum reasonable extent." Arguably, this policy favors higher energy charges and lower customer charges.

B. Positions of the Parties

1. Parties Supporting Higher Monthly Customer Charges

Citing Xcel's CCOSS, both Xcel and the Department favored increasing the monthly customer charge for the Residential Service and Residential Time-of-Day Service rate schedules; Xcel also proposed to increase the customer charge for Small General Service and Small General Time-of-Day Service. Specifically, Xcel proposed an increase of $2.00 per month, while the Department favored an increase of $1.25. In support of their positions, these parties variously argued as follows:

Rate design requires balancing economic efficiency with concern for fairness, affordability, stability, and other matters.

Xcel argued that setting the price of energy closer to its variable marginal cost would provide more efficient price signals. It would let the ratepayer bear more of the consequences of a choice to consume or conserve an extra kWh, or to acquire a different source of electricity such as photovoltaic cells. On the other hand, setting the price of energy above its marginal cost would give ratepayers an exaggerated incentive to conserve, move, or seek other energy sources. And as ever more customer-related costs are recovered based on the level of energy consumption, the larger share of these costs will be borne by customers with high energy usage. Xcel claimed that this dynamic results in high-usage customers subsidizing low-usage customers.

Xcel's CCOSS indicated that a revenue stream of $18.65 per month would be necessary to defray Xcel's average customer-related costs for residential ratepayers. Xcel's and the Department's proposed customer charges would recover only about half this amount. This is consistent with the Commission's decision in Xcel's last rate case, when the Commission established a residential customer charge that would recover roughly half of the average customer-related costs identified in Xcel's CCOSS.

Low-income households tend to consume less energy than average but, according to Xcel, only slightly less. And Xcel argued that many low-income households consume more energy than average.

Xcel and the Department acknowledge that Minnesota Statues section 216B.03 directs the Commission to set rates to encourage energy conservation and renewable energy use "to the maximum reasonable extent." But they argue that recovering ever more costs on the basis of energy consumption eventually becomes unreasonable because it requires an excessive sacrifice of economic efficiency, fairness, affordability, and other concerns.

2. Parties Opposing Higher Customer Charges

AARP, the CEO, ECC, Minneapolis, the OAG, and the SRA opposed increasing the monthly customer charge for the Residential and Small General Service tariffs. Indeed, AARP and the OAG argued for reducing the charge by $1.00 per month starting in 2016. And the OAG argued for reducing the charge by an additional $1.00 per month by the end of the multiyear rate plan's third year.

These parties argued variously that rate designs with higher energy charges and lower monthly customer charges maintain the health and safety of low-income customers, promote affordability, and enhance customer control over energy bills. They argued that the traditional rationale for higher residential customer charges—ensuring stable revenues for the utility—is obviated by Xcel's revenue-decoupling pilot program, which moderates Xcel's risk that mild weather or changes in usage may depress electricity sales.

These parties argued that Minnesota Statutes section 216B.03—directing the Commission to set rates to encourage conservation to the maximum reasonable extent—favors rate designs with higher energy charges and lower customer charges. That is because higher energy costs will tend to discourage energy consumption and reward energy conservation. In contrast, a CEO study found that Xcel's favored rate design would increase energy sales by 0.8 percent—effectively nullifying two-thirds of the state's goal in establishing the Conservation Improvement Program of reducing energy sales by 1.2 percent.

The CEO argued that CCOSSs are designed to aid revenue apportionment among customer classes, and are not intended for the purpose of rate design within classes. If the Commission wants to identify a utility's average customer costs, the CEO and OAG argued, it should identify the specific plants and services that are required to connect a new customer to a utility's network, or maintain an additional customer on the network. Of all the CCOSSs in the record, the CEO and OAG argued that the Basic Customer Method comes closest to providing this analysis. The OAG identified average customer-related costs of between \$3.00 and \$5.00 per month, while the CEO's study estimated the cost at \$5.97 per month

Finally, it was undisputed that low-income households tend to consume less energy than average households. As noted previously, most low-income households do not receive LIHEAP assistance. These parties argued that the Commission should design rates to minimize the burdens to those least able to bear them. That would mean keeping customer charges low, even at the expense of higher energy charges.

C. The Recommendation of the Administrative Law Judge

The ALJ rejected the claim that the record demonstrated the economic efficiency of any given monthly customer charge. The ALJ acknowledged that by setting prices equal to marginal cost, the Commission could let customers bear the social cost of increasing consumption, and the social benefits of conserving. But the ALJ found that marginal cost could not be determined on the basis of the historical cost data in the record. Therefore the ALJ found no support for arguments purporting to show how a given fixed customer charge would promote economic efficiency.

Having rejected the arguments supporting a higher monthly customer charge, the ALJ also declined to recommend lowering the charge due to the adverse consequences for high-usage households. Consequently the ALJ recommended that the Commission retain the current schedule of customer charges for residential and small commercial customers.

D. Commission Action

The Commission concurs with the ALJ that the goal of setting efficient price signals would ideally be informed by a rigorous calculation of marginal cost, and that this number can be difficult to derive from the record of a rate case. But more importantly, sending efficient price signals is merely one of the Commission's objectives. Setting the price of energy at the marginal cost of production, and setting the customer charge at the marginal cost to connect or maintain a customer, may not permit a utility to recover its cost of service.

The Commission also seeks to set Xcel's rates in a manner that would permit a prudently-managed utility serving Xcel's service area to be able to recover its costs and earn a fair return. CCOSSs are designed to aid a regulator's efforts to apportion revenue responsibility among classes of customers. And the rate-design process is designed to ensure that the utility's rates, multiplied by the amount of service the utility is forecast to provide, will generate the revenues apportioned to each class.

Minnesota Statues section 216B.03 directs the Commission to design rates to encourage conservation and the use of renewable energy. Minnesota Statutes section 216B.16, subdivision 15, directs the Commission to consider ability to pay when designing rates. The Commission also values rate continuity and the avoidance of rate shock. These objectives conflict.

In sum, the Commission lacks the information that would let it achieve perfect economic efficiency, and moreover, the Commission has a duty to pursue revenue objectives that are inconsistent with marginal-cost pricing. Nevertheless, the Commission may make reasonable inferences about which rate proposals are more likely to send appropriate price signals, even if imperfectly.

Having reviewed the arguments of the parties and balanced the competing considerations, the Commission is not persuaded that any party has demonstrated the need to alter the monthly customer charges that Xcel assesses on residential and small business customers—whether to increase or decrease them. Consequently those monthly customer charges will be retained.

XXXI. Interruptible Service and Discounts

A. Introduction

Interruptible customers forgo firm electric service in exchange for a discount. That is, customers who subscribe for interruptible service receive electricity at a lower price than customers receiving firm service, but they agree to promptly curtail their consumption of electricity upon request.

Xcel offers two tiers of Interruptible Service for its Commercial & Industrial Demand customers. Under Tier 1, a customer signs a ten-year contract with the option of canceling the contract after three years' notice, and a guarantee that Xcel will not interrupt the customer's service for more than 150 hours. Under Tier 2, the customer signs a five-year contract with the option of cancelling after six months' notice, and a guarantee that Xcel will not interrupt the customer's service for more than 80 hours.

Interruptible service benefits both the utility and the customer. Xcel gains the benefit of reduced supply-side capacity obligation resulting from the option to interrupt service to an interruptible customer.

According to MISO rules, utilities must have planning resource credits or accredited generating capacity to reliably serve its firm customers. Interruptible customers that are accredited with MISO reduce the amount of supply-side capacity that Xcel must maintain on its system.

At the same time, the customer gains the benefit of receiving electric service at a discounted rate. The interruptible discount increases as the customer's average July and August peak-hours maximum controllable demand increases. As part of the Settlement, Xcel proposed increasing controllable demand charges in 2016, 2017, and 2019—but proposed increasing the interruptible discount only in 2016, and only by 0.6 to 2.0 percent, with an average increase of 1.84 percent. Parties disagree about whether the overall terms of interruptible service are sufficient to attract the appropriate level of participation.

B. Positions of the Parties

1. The Chamber and XLI

The Chamber and XLI argued that Xcel was mismanaging its interruptible service, making it less attractive even as it becomes more important. They variously argued as follows:

- Utilities throughout the US, including Xcel, are making plans to retire their coal-fired generators. This change will strain the capacities of the remaining generators, and enhance the value of customers willing to subscribe for interruptible service.

- Xcel has begun testing its interruptible-service program by calling on subscribers to fully curtail service at short notice, contrary to MISO's tariff and business practices. Apparently many large commercial and industrial customers found it burdensome to shut down their operations merely for a test. By March 2016, Xcel's system lost 45 megawatts (MW) of interruptible load: 78 customers canceled their contracts and 333 customers chose to reduce the amount of load subject to interruption. Arguably this has reduced Xcel's flexibility for managing emergencies, and increased the amount of load for which Xcel must secure supply-side capacity resources.

- As previously noted, Xcel proposed increasing the demand charge for its demand-metered customers throughout this multiyear rate plan, but proposed only a single, modest increase in the interruptible discount. When Xcel increases its demand charge at a faster rate than it increases the discount for interruptible service, arguably Xcel is diluting the value of the discount.

While the Chamber and XLI were in substantial agreement about the nature of the problem, they proposed different remedies.

XLI objected to the size of Xcel's proposed increase in the interruptible discount, and recommended that the Commission maintain the current demand charge for Tier I, Short-Notice interruptible service. Comparing the benefits of XLI's interruptible load to the cost and benefits of having a small generator on hand, XLI argued that Xcel's interruptible discount undervalues the benefits provided by interruptible customers.

In contrast, the Chamber withdrew its objections to Xcel's 2016 proposed change to the interruptible discount. But the Chamber maintained that when Xcel increases the demand charges for the Commercial and Industrial Demand class in 2017 and 2018, it should increase the interruptible discount by the same percentage.

The Chamber also recommended that Xcel discontinue its practice of subjecting interruptible customers to spot checks that require customers to shut down their operations. The Chamber claimed that mock tests, as specified in the MISO tariff and business practices manuals, would suffice.

2. The Department

The Department recommended that the Commission approve Xcel's proposed increase in the discount rate. The Department observed that Xcel's infrequent interruption of service to interruptible customers may not be maximizing the program's benefits to the system. The Department concluded that the increased discount would help moderate the consequences of the proposed rate increase for the Commercial & Industrial Demand class, and maintain the current balance of costs and benefits reflected in the terms for firm and interruptible service.

The Department suggested that the challenge of establishing the optimal terms for Xcel's interruptible service, and the optimal strategies for exercising the option to interrupt service, might be addressed more productively in the Commission's current docket exploring changes to Xcel's rate design.[53]

3. Xcel

Xcel defended its proposed rate increase for the Commercial & Industrial Demand class, and its proposed increase to the interruptible discount.

Xcel stated that it disagrees with the Chamber's calculations of appropriate discount amounts for 2017 and 2018. However, Xcel supported the proposal to make proportionate increases to the interruptible discount in 2017 and 2018 when it implements increases to the demand charge.

In response to the Chamber's proposal to eliminate mandatory testing of its interruptible-service customers and instead conduct mock tests, Xcel noted that mandatory testing for interruptible service customers is provided for by Xcel's tariff. Moreover, Xcel stated that such testing is appropriate and advisable.

4. The Recommendation of the Administrative Law Judge

The ALJ acknowledged that interruptible customers permit Xcel to reduce the amount of generation capacity it needs to meet its peak demand, but did not agree that the value of the interruptible discount must reflect the avoided cost of that standby power. Rather, the ALJ concluded that the size of the discount reflects a market-based approach to valuing interruptible load in order to attract the optimal amount of interruptible load.

The ALJ shared the Chamber's and XLI's concern about the number of Xcel customers that recently switched from interruptible service to firm service, but could not establish a standard for judging whether Xcel's current interruptible load was optimal or not.

The ALJ agreed with the Department that the interruptible load program should be reviewed in the Commission's investigation into Xcel's rate design.

Finally, the ALJ concurred with the recommendation to increase the interruptible discount in proportion to any increase in the demand charge for the Commercial & Industrial Demand class after 2016. If the Commission were to adopt the Settlement, this would mean increasing the interruptible discount in 2017 and 2019.

5. Commission Action

XLI argued that Xcel's rate proposals fail to regard interruptible service as the equivalent of supply-side capacity, and thus Xcel neglected to offer a discount that is commensurate with the benefit. In response, the Department and the ALJ concluded that the optimal size of Xcel's discount cannot be determined on the basis of an avoided-cost calculation. The Commission agrees in part: Interruptible service reduces Xcel's supply-side capacity resource needs, and thus

[53] *In the Matter of an Alternative Rate Design Stakeholder Process for Xcel Energy*, Docket No. E-002/CI-15-662 (Xcel's Rate Design Docket).

optimal size of the interruptible-service discount could be determined on the basis of XLI's avoided-cost calculation. But additional factors should be considered.

Evaluating the terms for interruptible service is akin to evaluating alternatives in a utility's resource plan. It requires comparing (a) the benefits to the utility from a vendor—that is, a customer willing to subscribe for interruptible service—to (b) the costs of securing those benefits. If the terms are not sufficiently attractive (discount too low, testing too onerous, service interruptions too frequent), then Xcel will not be able to attract and maintain enough participation in the program, and will have to acquire additional supply-side capacity instead. But if the terms are made too attractive (discount needlessly large, testing too lax, service maintained even when unduly expensive to the utility), then Xcel will needlessly forgo revenues and savings, and may imperil system reliability.

Given the delicacy of this trade-off, this Commission—like the Chamber, the Department, and the ALJ—is inclined to give Xcel leeway in this case to set the terms for interruptible service. Consequently the Commission will approve an increase in the discount level for 2016 as proposed by Xcel. Xcel claims that increasing the discount by an average of 1.84 percent would help maintain the appropriate balance of costs and benefits offered by its firm and interruptible services. The Commission finds this argument to be reasonable, and will affirm it.

But this balance would be upset if, as planned, Xcel were to increase its demand charges without making a corresponding increase in the interruptible discount. For this reason, the Commission will also adopt the recommendation of the Chamber, the Department, and the ALJ that as Xcel increases the demand charges for the Commercial & Industrial Demand class, it should increase the size of the interruptible credit in the same proportion. Because the Settlement does not provide for rate increases in 2018, these increases would occur in 2017 and 2019.

Finally, the Chamber and XLI objected to Xcel's practice of periodically requiring interruptible customers to fully curtail their consumption of electricity in order to test their ability to do so. The Commission is open to the possibility that Xcel could obtain the necessary assurances without compelling commercial and industrial customers to take the final step and curtail their operations. If MISO's accreditation policies do not require that type of testing, the Commission will not either.

Consequently the Commission will direct Xcel to conduct testing of interruptible customers consistent with the testing required by MISO's tariffs and Business Practice Manuals, and to revise its tariff accordingly.

XXXII. Miscellaneous Rate-Design Topics

Finally, the ALJ recommended that the Commission direct parties to take additional procedural steps with respect to the following four rate-design topics:

- *Time-of-Use rates for Commercial & Industrial classes:* Refer the matter to Xcel's alternative-rate-design proceeding.
- *Time-of-Use rates for Residential class:* Refer the matter to Xcel's alternative-rate-design proceeding.

- *The Renew-A-Source program for Commercial & Industrial classes:* Initiate discussions among the parties, and refer the matter to Xcel's alternative-rate-design proceeding.
- *The BIS Rider:* Initiate an investigation.

Having reviewed the arguments of the parties, the Commission is not persuaded that the record justifies directing parties to take additional procedural steps on these matters. The parties may exercise their own discretion in choosing what additional relief to pursue, if any.

ILLUSTRATIVE FINANCIAL SCHEDULES

A. Gross Revenue Deficiency

Based on the above findings, the Commission concludes that, as shown below, the 2016 test year total gross revenue deficiency is $134,966,000, the 2017 and 2018 plan year total gross revenue deficiency is $194,824,000 and the 2019 plan year total gross revenue deficiency is $244,721,000:

Revenue Deficiency - Minnesota Jurisdiction
Test Year Ending December 31, 2016 and 2017-2019 Plan Years
($000's)

Line No.		2016 Test Year	2017 Plan Year	2018 Plan Year	2019 Plan Year
1	Average Rate Base	$7,443,512	$7,426,751	$7,293,821	$7,202,334
2	Operating Income	$413,030	$371,587	$368,756	$338,552
3	AFUDC	$34,096	$40,744	$34,150	$27,894
4	Total Available for Return	$447,126	$412,331	$402,906	$366,445
5	Overall Rate of Return (Line 4 / Line 1)	6.01%	5.55%	5.52%	5.09%
6	Required Rate of Return	7.07%	7.09%	7.09%	7.08%
7	Required Operating Income (Line 1 x Line 6)	$526,256	$526,557	$517,132	$509,925
8	Income Deficiency (Line 7 - Line 4)	$79,130	$114,226	$114,226	$143,480
9	Gross Revenue Conversion Factor	1.705611	1.705611	1.705611	1.705611
10	Revenue Deficiency (Line 8 x Line 9)	$134,966	$194,824	$194,824	$244,721
11	Retail Related Revenues Under 2016 Present Rates	$2,956,319	$2,956,319	$2,956,319	$2,956,319

B. Rate Base Summary

Based on the above findings, the Commission concludes that, as shown below, the appropriate rate bases are $7,443,512,000 for the 2016 test year, $7,426,751,000 for the 2017 plan year, $7,293,821,000 for the 2018 plan year, and $7,202,334,000 for the 2019 plan year:

Rate Base Summary - Minnesota Jurisdiction
Test Year Ending December 31, 2016 and 2017-2019 Plan Years
($000's)

Line No.		2016 Test Year	2017 Plan Year	2018 Plan Year	2019 Plan Year
	ELECTRIC PLANT IN SERVICE				
1	Production	9,178,231	9,443,128	9,749,355	10,060,608
2	Transmission	2,203,520	2,262,072	2,301,595	2,397,725
3	Distribution	3,272,959	3,391,796	3,516,302	3,658,370
4	General	727,748	777,297	827,938	888,530
5	Common	540,996	639,611	725,535	781,187
6	Total Utility Plant In Service	15,923,454	16,513,905	17,120,725	17,786,420
	RESERVE FOR DEPRECIATION				
7	Production	4,941,309	5,290,771	5,644,011	6,015,790
8	Transmission	533,116	552,513	585,833	619,062
9	Distribution	1,232,993	1,277,293	1,333,146	1,391,483
10	General	267,760	328,863	390,194	451,746
11	Common	268,091	313,919	362,619	412,713
12	Total Reserve For Depreciation	7,243,269	7,763,360	8,315,803	8,890,795
	NET PLANT IN SERVICE				
13	Production	4,236,922	4,152,357	4,105,344	4,044,818
14	Transmission	1,670,404	1,709,559	1,715,763	1,778,663
15	Distribution	2,039,966	2,114,503	2,183,156	2,266,887
16	General	459,988	448,435	437,744	436,784
17	Common	272,905	325,691	362,916	368,473
18	Net Utility Plant In Service	8,680,185	8,750,545	8,804,922	8,895,625
19	Construction Work in Progress	453,110	482,754	422,411	380,350
20	Accumulated Deferred Income Taxes	(1,911,697)	(2,023,988)	(2,153,354)	(2,302,072)
	Other Rate Base Items				
21	Cash Working Capital	(100,003)	(107,935)	(111,985)	(111,130)
22	Material & Supplies	135,797	135,797	135,797	135,797
23	Fuel Inventory	73,476	73,476	73,476	73,476
24	Non-Plan Assets & Liabilities	(3,716)	5,666	15,903	27,456
25	Customer Advances	(5,562)	(5,562)	(5,562)	(5,562)
26	Customer Deposits	(28,127)	(28,127)	(28,127)	(28,127)
27	Prepayments	89,307	86,772	86,374	85,941
28	Regulatory Amortizations	60,741	57,353	53,966	50,579
29	Total Other Rate Base	221,913	217,440	219,842	228,430
30	TOTAL AVERAGE RATE BASE	7,443,512	7,426,751	7,293,821	7,202,334

C. Operating Income

Based on the above findings, the Commission concludes that, as shown below, the appropriate operating incomes are $447,126,000 for the 2016 test year, $412,331,000 for the 2017 plan year, $402,906,000 for the 2018 plan year, and $366,445,000 for the 2019 plan year:

Operating Income Summary - Minnesota Jurisdiction
Test Year Ending December 31, 2016 and 2017-2019 Plan Years
($000's)

Line No.		2016 Test Year	2017 Plan Year	2018 Plan Year	2019 Plan Year
	OPERATING REVENUES				
1	Retail Revenue	2,955,675	2,955,675	2,955,675	3,051,778
2	Interdepartmental	644	644	644	672
3	Other Operating Revenue	593,580	618,227	660,562	687,000
4	Total Operating Revenue	3,549,899	3,574,546	3,616,881	3,739,450
	EXPENSES				
	Operating Expenses				
5	Fuel & Purchased Energy	1,001,096	1,001,136	1,001,199	1,125,206
6	Power Production	679,459	685,084	687,737	691,533
7	Transmission	204,923	209,530	217,148	243,697
8	Distribution	108,023	110,120	112,784	111,186
9	Customer Accounting	49,315	49,956	50,820	50,555
10	Customer Service and Information	94,968	94,983	94,998	95,067
11	Sales, Econ Dev, & Other	69	70	71	69
12	Administrative and General	206,324	211,033	216,787	224,433
13	Total Operating Expenses	2,344,178	2,361,911	2,381,546	2,541,744
15	Depreciation	449,537	522,206	540,936	568,522
16	Amortization	39,359	39,273	39,273	21,871
	TAXES				
17	Property Taxes	178,439	186,760	192,275	198,796
18	Deferred Income Tax & ITC	110,661	127,890	122,206	107,334
19	Federal & State Income Tax	(12,855)	(63,320)	(56,874)	(67,264)
20	Payroll & Other	27,550	28,238	28,763	29,896
21	Total Taxes	303,795	279,569	286,371	268,761
22	Total Expenses	3,136,869	3,202,959	3,248,126	3,400,898
22	Allowance for Funds Used During Construction (AFUDC)	34,096	40,744	34,150	27,894
24	Total Operating Income	447,126	412,331	402,906	366,445

ORDER

1. The Commission adopts the ALJ's Findings of Fact, Conclusions of Law, and Recommendations to the extent that the ALJ's Report is consistent with the decisions herein.

2. The Commission hereby approves the August 16, 2016 Stipulation of Settlement in its entirety.

3. Xcel shall work with Commission and Department staff to develop a capital-projects true-up compliance reporting tool that meets the regulatory needs of the agencies, to be filed annually.

4. The Commission hereby grants a variance to Minn. R. 7825.3300; Xcel shall use an annual 4.81% interest rate to calculate interim-rate refunds.

5. Xcel shall make a compliance filing once the Mankato II in-service date becomes certain. If the in-service date does not materialize by 2019, the compliance filing should include the delay's 2019 revenue-requirement impact and how Xcel proposes to address it.

6. Within 90 days of the date of this order, Xcel shall make a compliance filing comparing final rate case expenses to the requested $3.34 million.

7. Xcel shall file, as a comparison, a true-up calculation based on actual (not weather-normalized) sales and revenue throughout the term of the multiyear rate plan.

8. A separate proceeding (Docket No. E-002/CI-17-401) will identify and develop performance metrics and standards, and potentially incentives, to be implemented during the multiyear rate plan. The Commission delegates to the Executive Secretary to issue notice(s), set schedules, and designate comment periods.

9. Regarding the Class Cost-of-Service Study:

   a. Xcel need not file a revised CCOSS for purposes of apportioning revenues among customer classes in this docket.

   b. Xcel shall report on methods to measure losses for Xcel's next rate case.

   c. In Xcel's next docket revising its Renewable Development Fund rider, any party may raise the issues identified by the Chamber regarding the allocation of RDF rider costs.

   d. In Xcel's next docket revising its Conservation Improvement Program rider, any party may raise the issues identified by the Chamber and XLI regarding the allocation of CIP costs.

   e. For purposes of Xcel's next rate case, Xcel shall adopt the recommendations of the ALJ with the following exceptions:

      i. Xcel need not adopt the ALJ's recommendations regarding the classification and allocation of distribution costs.

      ii. Xcel shall base the D10S capacity allocator on Xcel's system peak coincident with MISO's system peak, incorporating any future changes to MISO's method for calculating the system peak.

10. Xcel shall apportion revenue responsibility among its customer classes throughout the duration of the multiyear rate plan as follows:

Residential	36.74%
C&I Non-Demand	3.51%
C&I Demand	58.86%
Lighting	0.90%

11. To mitigate the consequences of residential rate increases, Xcel shall do the following:

    a. Make a filing within 120 days of this order containing

    - information regarding the availability of Low-Income Home Energy Assistance Program (LIHEAP) funds available for Xcel's low-income customers,
    - data regarding the amount of LIHEAP funding that is not claimed during the year, and
    - a plan to improve its outreach to low-income customers

    b. Make a filing every six months containing

    - The number of past-due residential customers and arrearage information and
    - The number of residential service disconnections

    c. Actively reach out to past-due customers in order to inform them about the availability of assistance from LIHEAP.

12. Xcel shall maintain its current monthly customer charge for Residential and Small Commercial customers.

13. Regarding interruptible service, the Commission takes the following actions:

    a. Authorizes Xcel to implement its original proposal for increases in its interruptible service discounts of between 0.6 and 2.0 percent with an average of 1.84 percent for the 2016 test year.

    b. Approves Xcel's 2016 proposed increases, but require that the 2017 and 2019 interruptible service discounts increase by the same percent increase as the proposed controllable demand charges.

    c. Requires Xcel to modify its interruptible-program testing requirements to be consistent with the testing provided for in the tariffs and Business Practices Manuals of the Midcontinent Independent System Operator, Inc.

14. The Commission takes no action on the following proposals:

    a. Changing the definition of "Peak Period" for Commercial & Industrial customers' Time-of-Use rates.

    b. Initiating a Time-of-Use pilot program for Residential customers.

    c. Developing a Renew-A-Source program for Large Industrial customers.

    d. Modifying the BIS Rider, or initiating an investigation of that rider.

15. Within 30 days, Xcel shall make the following compliance filings:

    a. Revised schedules of rates and charges reflecting the revenue requirement and the rate-design decisions herein, along with the proposed effective date, and including the following information:

        i. Breakdown of Total Operating Revenues by type;

        ii. Schedules showing all billing determinants for the retail sales (and sale for resale) of electricity. These schedules shall include but not be limited to:

            1. Total revenue by customer class;

            2. Total number of customers, the customer charge, and total customer charge revenue by customer class; and

            3. For each customer class, the total number of energy- and demand-related billing units, the per-unit energy and demand cost of energy, and the total energy- and demand-related sales revenues.

        iii. Revised tariff sheets incorporating authorized rate-design decisions; and

        iv. Proposed customer notices explaining the final rates, the monthly basic service charges, and any and all changes to rate design and customer billing.

    b. A revised base cost of energy, supporting schedules, and revised fuel-adjustment tariffs to be in effect on the date final rates are implemented.

    c. A summary listing of all other rate riders and charges in effect, and continuing, after the date final rates are implemented.

    d. A computation of the CCRC based upon the decisions made herein.

    e. A schedule detailing the CIP tracker balance at the beginning of interim rates, the revenues (CCRC and CIP Adjustment Factor) and costs recorded during the period of interim rates, and the CIP tracker balance at the time final rates become effective.

    f. A proposal to make refunds of interim rates to affected customers consistent with the Commission's decisions herein.

16. Comments may be filed on all compliance filings within 30 days of the date they are filed.

17. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Daniel P. Wolf

Daniel P. Wolf
Executive Secretary

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Guide to the Class Cost of Service Study (CCOSS) Northern States Power Co Electric

I. Overview

Simply stated, the purpose of the Northern States Power Company (NSP) electric Class Cost of Service (CCOSS) is to allocate ***joint*** (e.g.) and ***common*** costs to the designated "classes" of service such as Residential, Non-Demand C&I and Demand C&I. For example, generation capacity costs are "joint" between time periods and overhead costs such as management, are "common" to multiple functions, such as distribution, transmission and generation. The CCOSS also assigns ***direct*** costs (e.g. a dedicated service extensions or dedicated substations), that may be associated with providing service to a particular customer from a specific class of service. The objective of the CCOSS is to make these cost ***allocations*** and ***assignments*** based on identifiable service requirements (e.g. kWh energy requirements and kW capacity requirements), which are the drivers of the costs.

The two basic types of costs are; (1) capital costs associated with investment in generation, transmission and distribution facilities and (2) on-going expenses such as fuel used to produce the energy, labor costs and numerous other operating expenses. The end result is an allocation of the total utility costs (i.e. the revenue requirements) to customer classes according to each class' share of the capacity, energy and customer service requirements.

II. Major Steps of the Class Cost of Service Study

A class cost of service study begins with a detailed documentation of the numerous budgetary elements of the total revenue requirement for the jurisdiction in question. The detailed jurisdictional revenue requirements are the data inputs to the CCOSS. At a high level, the CCOSS process consists of the following three (3) basic steps:

1. Functionalization – The identification of each cost element as one of the basic utility service "functions" (e.g. generation, transmission, distribution and customer).
2. Classification – The classification of the functionalized costs based on the billing component/determinant that each is associated with (e.g. kWs of capacity, kWhs of energy or number of customers).
3. Allocation – The allocation of the functionalized and classified costs to customer classes, based on each class' respective service requirements (e.g. kWs of capacity, kWhs of energy and the number of customers, expressed in terms of a percentage of the total jurisdiction requirement).

III. Step 1: Functionalization

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

Function	**FERC Accounts**	**Sub-Function**	**Description**
Generation	120, 310-346, 500-557	"Energy-related"	Includes the fixed costs of generation plant investment and purchase capacity costs, which have been stratified as "energy-related."
		Summer "capacity-related."	Includes the fixed costs of generation plant investment and purchase capacity costs stratified as "capacity-related" and which are associated with the system summer peak load requirements.
		Winter "capacity-related."	Includes the fixed costs of generation plant investment and purchase capacity costs stratified as "capacity-related" and which are associated with the system winter peak load requirements.
		On-Peak Energy	Includes costs for fuel and purchases of energy for on-peak hours.
		Off-Peak Energy	Includes costs for the fuel and purchases of energy for off-peak hours.
Transmission	350-359, 560-579	None	Includes costs of transmission lines and associated substation facilities used to transport power from its origin generation stations or delivery points to the high voltage side of the distribution substations.
Distribution	360-368, 580-598	Distribution Substations	Includes costs of the facilities (e.g. transformers and switch gear) between the transmission and distribution systems.
		Primary Distribution System "Capacity."	Includes costs of the "capacity" portion (as distinguished from the "customer" portion) of primary voltage conductors, transformers and related facilities.
		Secondary Distribution System "Capacity."	Includes costs of the "capacity" portion (versus "customer" portion) of secondary voltage conductors, transformers, customer services and related facilities.
Customer	360-369, 580-598, 901-916	"Customer" portion of the Primary and Secondary Systems	Includes costs for the "customer" portion of primary and secondary conductors, transformers, customer service drops, related facilities and the costs of metering.
		Energy Services	Includes costs for meter reading, billing, customer service and information, and back office support.

A. Generation Cost Stratification

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

For example, the plant stratification analysis used in the current rate case is shown in the table below. It compares the then current-dollar replacement costs of each plant type, to develop stratification percentages.

Plant Type	$/kW	Capacity Ratio	Capacity %	Energy %
Peaking	$792	$792 / $792	100%	0%
Nuclear	$4,146	$792 / $4,146	19.1%	80.9%
Fossil	$2,022	$792 / $2,022	39.2%	60.8%
Combined Cycle	$1,037	$792 / $1,037	76.3%	23.7%
Hydro	$5,601	$792 / $5,601	14.1%	85.9%
Wind	$20,319	$792 / $20,319	3.9%	96.1%

This process of "stratifying" the revenue requirements of the generation plant is accomplished by applying these stratification percents to each component of the revenue requirements (e.g. book investment, accumulated depreciation, net plant, cost of capital, income taxes, etc.), for each generation plant type.

B. Summer/Winter Split of Generation Capacity-Related Costs

Once the "capacity-related" portion of generation plant costs has been quantified, they are further separated into summer and winter sub-functions. The seasonal sub-function portions are determined as follows.

First, the 12 monthly System peak loads are grouped into a 4-month summer (June, July, August and September) and an 8-month winter seasons. Second, the average hourly load for the year is subtracted from each monthly peak. Third, the remaining monthly excess loads are averaged for each season and the ratio of these two average seasonal "excess" loads is used to assign the "capacity- related" portion of fixed generation costs to the seasons. This calculation for the current rate case is shown below.

(1)	(2)	(3)	(4) = (3) minus 5,155
Month	**Season**	**Monthly NSP System Peak Load**	**Monthly Peak in Excess of Average Hourly Load**
Jan	Winter	6,674	1,519
Feb	Winter	6,349	1,194
Mar	Winter	5,993	838
Apr	Winter	5,659	504
May	Winter	6,281	1,126
Jun	Summer	8,013	2,858
Jul	Summer	9,310	4,155
Aug	Summer	9,524	4,369
Sep	Summer	8,481	3,326
Oct	Winter	6,013	858
Nov	Winter	6,195	1,040
Dec	Winter	6,819	1,664
		6,674	1,519
Average Annual Load		**5,155**	
Average Monthly Excess			
Average of Summer Months			3,677
Average of Winter Months			1,093
Total			4,771
Summer Percent			**77.08%** = 3,677/4,771
Winter Percent			**22.92%** = 1,093 / 4,771.

As shown above 77.08% of generation capacity costs were assigned to the summer season while 22.92% were assigned to winter, thereby separating total generation capacity-related costs into summer and winter seasons.

IV. Step 2: Cost Classification

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

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

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

Function/Sub-Function	**Cost Classification**		
	Demand	**Energy**	**Customer**
Summer Capacity-Related Fixed Generation	X		
Winter Capacity-Related Fixed Generation	X		
Energy-Related Fixed Generation	X		
Off-Peak Energy (Fuel and Purchased Energy)		X	
On-Peak Energy (Fuel and Purchased Energy)		X	
Transmission	X		
Distribution Substations	X		
Primary Lines	X		X
Primary Transformers	X		
Secondary Lines	X		X
Secondary Transformers	X		X
Service Drops	X		X
Metering			X
Energy Services			X

As shown in the table above, primary lines, secondary lines, secondary transformers and service drops are classified as both "demand" and "customer" related costs. Costs of these sub-functions are driven by **both** the number of customers on the distribution system and the capacity requirements they place on the system. The analysis used to separate these costs into demand and customer components is called the Minimum Distribution System (MDS) method.

The Minimum Distribution System method involves comparing the cost of the minimum size of each type of facility used, to the cost of the actual sized facilities installed. The cost of the minimum size facilities determines the "customer" component of total costs and the "capacity" cost component is the difference between total installed cost and the minimum sized cost.

The table also shows the percent of each cost element that was classified as "customer" related based on the most recent Minimum System study.

Equipment Type	**% Classified as "Customer" Related**
Overhead Lines Primary	42.3%
Primary Transformers	0.0%
Overhead Lines Secondary	54.9%
Underground Lines Primary	85.9%

Underground Lines Secondary	54.3%
Line Transformers Secondary	48.8%
Services	72.7%

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

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

- Direct Assignment - A small but sometimes important portion of costs can be directly assigned to a specific customer of a particular customer class, because these costs can be exclusively identified as providing service to a particular customer. Examples of costs that are directly assigned include:
  - Customer-dedicated transmission radial lines or dedicated distribution substations
  - Street lighting facility costs
- Allocation - Most electric utility costs are incurred in common or jointly in providing service to all or most customers and classes. Therefore, allocation methods have to be developed for each functionalized and classified cost component. The allocation method is based on the particular measures of service that is indicative of what drives the costs.
  - Class allocators (sometimes called allocation strings) are simply a "string" of class percentages that sum to 100%.
  - There are 2 types of allocators:
    - External Allocators –These are the more interesting allocators that are based on data from outside the CCOSS model (e.g. load research data, metering and customer service-related cost ratios). In general, there are three types of external allocators:
      - Capacity –related (sometimes referred to as Demand) allocators such as:
        - System coincident peak (CP) responsibility or class contribution to system peak (1CP, 4CP or 12CP)
        - Class peak or non-coincident peak
        - Individual customer maximum demands
      - Energy-related allocators such as:
        - kWh at the customer (kWh sales)
        - kWh at the generator (kWh sales plus loses)
        - kWh energy, weighted by the variable cost of the energy
      - Customer-related allocators
        - Number of customers
        - Weighted number of customers, where the weights are based on cost of meters, billing, meter-reading, etc.

      Details on the external allocators used in the CCOSS model are shown in Appendix 1.

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

- PTD – Production, transmission and distribution plant investment.
- OXDTS – Distribution O&M expenses without supervision and miscellaneous expenses.

Details on the development of the internal allocators used in the CCOSS model are shown in Appendix 2.

VI. Customer Class Definitions

Ideally, there would be no customer class groupings and cost allocation would reflect the unique costs of each individual customer. Because this is not possible, it is necessary to develop a cost study process that identifies costs of service for groups of customers ("classes") where the customers of the class have similar cost/service characteristics. The basic classes of service employed in the Company's CCOSS are the following:

1. Residential
2. Non Demand Metered Commercial
3. Demand Metered Commercial & Industrial and
4. Street & Outdoor Lighting

Also, because of the significantly different distribution-functional requirements of customers within the Demand Metered C&I class, the Company's CCOSS also identifies the cost differences associated with the following distribution-function requirements within this class:

1. Secondary
2. Primary
3. Transmission Transformed
4. Transmission

More detail on customer class definitions is shown in Appendix 3.

VII. CCOSS Data Inputs

As noted earlier, there are a large number of inputs to the CCOSS model including detailed rate base and expense items from the Jurisdictional Cost of Service Study (JCOSS) as well as numerous inputs from other sources used to develop external allocators.

VIII. Organization of the CCOSS Model

The CCOSS model consists of numerous worksheets which show costs by customer class in Total (as shown on the worksheet tab labeled "TOT") and at the following more detailed levels including Billing Unit, Function and Sub-function as shown below:

1. Billing Unit:

   a. Customer (Cus)

b. Demand (Dmd)
c. Energy (Ene)

2. Function and Associated Sub-Function:

a. Energy (Ene)
 a) On-Peak Energy (On)
 b) Off-Peak Energy (Off)

b. Generation (Gen_Dmd): Sub-functions include:
 a) Summer Capacity-Related Plant (Summ)
 b) Winter Capacity-Related Plant (Wint)
 c) Energy-Related Plant (Base)

c. Transmission (Transco)

d. Distribution (Disco): Sub-functions include:
 a) Distribution Substations (Psub)
 b) Primary Voltage? (Prim)
 c) Secondary Voltage? (Sec)

e. Customer (Cus): Sub-functions include:
 a) Service Drops (Svc_Drop)
 b) Energy Services (En_Svc)

In the CCOSS spreadsheet there is a separate worksheet tab for each of the above billing units, functions and sub-functions. The label for each worksheet tab is show in parentheses above. This multi-level breakdown of costs is useful for designing rates as well as for determining class revenue responsibilities.

IX. CCOSS Calculations

Listed below are important calculations that are part of the CCOSS model. These calculations occur at the "TOT" layer of the CCOSS as well as each of the "sub-layers" for each billing component, function and sub-function. Showing results at the more detailed billing component, function and sub-function levels is important for rate design purposes, as well as other analyses such as the development of voltage discounts.

A. Rate Base Calculation

Rate Base = Original Plant in Service – Accum. Depr + CWIP + Other Additions

The above rate base calculation occurs on "TOT" layer as well as each function/sub-function layer.

B. Revenue Requirements Calculation (Class Cost Responsibility)

The Revenue Requirements Calculation (sometimes referred to as the "Backwards Revenue Requirement Calculation) is used to calculate "**cost**" responsibility for each customer class. This has to be done within the CCOSS model because the JCOSS model does it only at the total jurisdiction level, not by class. The class "**cost**" responsibility is based on the same return on rate base for each class that is equal to the overall proposed rate of return. In other words, class revenues requirements are calculated to provide the same return on rate base for each customer class. This calculation occurs on the "TOT" layer as well as for each function, sub-function and billing component after all expenses and rate base items have been allocated. As such, class cost responsibility is available for each function, sub-function and billing component. This analysis serves a starting point for rate design. The formula is shown below:

Retail Revenue Requirement = Expenses (including off-setting credits from Other Operating Revenues)
+
(Return on Equity x Rate Base) x 1 / (1-Tax Rate)
+
(Tax Additions – Tax Deductions) x Tax Rate / (1-Tax Rate)
+
AFUDC

Where:

Expenses = O&M + Book Depreciation + Real Estate & Property Tax + Payroll Tax
+ Net Investment Tax Credit – Other Retail Revenue – Other Oper. Revenue

Tax Additions = Book Depreciation + Deferred Inc Tax + Net Inv Tax Credit
+ Other Misc Expenses.

Tax Deductions = Tax Depreciation + Interest Expense + Other Tax Timing Diff

C. Total Return and Return on Rate Base (Based on Class Revenue Responsibility)

After rates have been designed and each class' "**revenue**" responsibility has been determined, the model calculates total return and return on rate base using the following formulas. These calculations are performed at both present and proposed rate levels.

Total $ Return = Revenue – O&M Expenses – Book Depr.
– Real Estate & Property Taxes– Provision for Deferred Inc Taxes – Inv. Tax Credits
– State & Federal Income Taxes + AFUDC

Percent Return on Rate Base = Total $ Return / $ Rate Base

After rates have been designed, the return on rate base is typically different for each customer class. In other words, the resulting class "**revenue**" responsibility differs from class "**cost**" responsibility.

XI. CCOSS Output

The filed output of the CCOSS model includes the "Tot" worksheet layer of the much larger model. The important output from the functional, sub-functional and billing component layers is presented on page 2 of this "TOT" layer. The following table lists what is shown on each CCOSS page when printed.

Final CCOSS Printout "Tot" Worksheet

CCOSS Section	**Page Number**	**Results Detail**	**Line Numbers**
Results Summary	1	Rate Base Summary	1-22
		Income Statement Summary	23A-32B
		Proposed Cost Responsibility at Equal ROR (the cost of service) compared to **Proposed** Rate **Revenue** Responsibility	33-45
	2	**Proposed Cost** Responsibility at Equal ROR (the cost of service) compared to **Present** Rate **Revenue** Responsibility	1-50
Rate Base Detail	3	Original Plant in Service	1-53
	4	MINUS Accumulated Depreciation	1-28
		MINUS Accumulated Deferred Income Tax	29-56
	5	PLUS Construction Work in Progress & Other Additions	1-35
		EQUALS Total Rate Base	36
Income Statement Detail	6	Present, Proposed and Equal Revenues	1-25A
		MINUS O&M Expenses part 1	26-40
	7	MINUS O&M Expenses part 2	1-34
	8	MINUS Book Depreciation	1-25
		MINUS Real Estate & Property Taxes	26-53
	9	MINUS Provision for Deferred Income Tax	1-28
		MINUS Investment Tax Credit	29-55
		EQUALS Present,, Proposed and Equal Operating Income Before Income Taxes	58A, 58B & 58C
	10 (Income Tax Calcs.)	Tax Additions	33-43
		MINUS Tax Deductions	1-32
		EQUALS Total Tax Adjustments	44
		PLUS Present, Proposed & Equal Operating Income Before Income Taxes	FROM Page 10 58A, 58B & 58C
		EQUALS Present and Proposed Taxable Income	45A, 45B & 45C
		MULTIPLIED BY State and Federal Tax Rates	
		EQUALS Present, Proposed and Equal State and Federal Income Taxes	46A, 46B & 46C
	10 (Total Return Calcs.)	Present, Proposed and Equal Operating Income Before Income Taxes	FROM Page 10, Rows 58A, 58B & 58C
		MINUS Present, Proposed and Equal State and Federal Income Taxes	46A, 46B & 46C
		EQUALS Present and Proposed Preliminary Return	47A, 47B & 47C
		PLUS AFUDC (from page 12)	48
		EQUALS Present, Proposed and Equal Total Return	49A, 49B & 49C

XI. CCOSS Output (continued)

CCOSS Section	**Page Number**	**Results Detail**	**Line Numbers**
Misc Calcs	11	AFUDC	1-26
		Labor Allocator	27-48
Allocator Data	12	Internal Allocators and Associated Data	1-39
	13	External Allocators and Associated Data	1-52

Direct Testimony and Schedules
Michael A. Peppin

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in North Dakota

Case No. PU-12-____
Exhibit___(MAP-1)

Class Cost of Service Study
and
Selected Rate Design

December 18, 2012

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Michael A. Peppin. My title is Principal Pricing Analyst.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. My qualifications include more than 30 years of experience with the Company in the areas of market research and cost-of-service analysis. A detailed statement of my qualifications and experience is provided as Exhibit___(MAP-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I present the Company's proposed Class Cost of Service Study (CCOSS) and selected items from the Company's proposed rate design. Company witness Mr. Steven V. Huso will present the remainder of the Company's proposed rate design changes.

Q. MR. PEPPIN, PLEASE LIST EACH OF THE COST OF SERVICE AND RATE DESIGN TOPICS YOU WILL ADDRESS IN YOUR TESTIMONY.

A. The topics I will address are as follows:

- Class Cost of Service Study Results
- Selected Rate Design Revisions – Voltage Discounts
- Selected changes to the Company's General Rules and Regulations

II. CLASS COST OF SERVICE STUDY

A. Proposed Class Cost of Service Study

Q. HOW DOES THE COMPANY'S PROPOSED CCOSS COMPARE WITH THAT APPROVED BY THE NORTH DAKOTA PUBLIC SERVICE COMMISSION IN THE COMPANY'S LAST GENERAL ELECTRIC RATE CASE, CASE NOS. PU-10-657 AND 11-55?

A. We updated the CCOSS to include 2013 test-year data, and made limited adjustments, as described below. All other CCOSS process and allocation methods are consistent with our previous rate case:

- Assignment of underground wiring capital costs;
- Classification and allocation of Other Production Operating and Maintenance (O&M) expenses; and
- Allocation of the capacity portion of Purchased Power Agreements (PPA).

Q. WHAT CHANGE HAS BEEN MADE TO THE ASSIGNMENT OF UNDERGROUND WIRING CAPITAL COSTS?

A. A new line was added to the CCOSS to directly assign a portion of underground wiring capital costs to the Street Lighting class. Previously, the Company only directly assigned a portion of overhead wiring capital costs to the Street Lighting class. However, in recent years, municipalities have typically requested underground rather than overhead wiring. To reflect this change, a Street Lighting line was added to the underground wiring detail within the Original Plant In Service area of the CCOSS. All subsequent cost areas within the CCOSS, such as Accumulated Depreciation and Provision for

Deferred Income Tax, also reflect the Street Lighting direct assignments to overhead and underground wiring, although not as many detail lines are shown in those areas.

Q. WHAT CHANGE HAS BEEN MADE TO THE ALLOCATION FOR OTHER PRODUCTION O&M EXPENSES?

A. In the Company's last electric rate case, Other Production O&M costs were separated into baseload and capacity subcomponents in a two-step process. Under the two-step process, eight percent of these costs were treated as fixed and allocated on demand. However, discussions with production plant management have indicated that a higher percentage of plant operating costs are fixed.

As a result, we reevaluated our process and eliminated the second separation step. Our updated process to determine the proportion of fixed versus variable costs splits total Other Production O&M into a Baseload sub-function, based on the ratio of Original Plant Investment that has been stratified as Energy- or Baseload-related (including nuclear fuel), as a percent of Total Production Plant Investment.

This updated allocation process results in 25 percent of the Other Production O&M costs being treated as fixed, which, according to our production plant management, more accurately reflects the fixed versus variable nature of Other Production O&M expenses.

Q. WHAT CHANGE HAS BEEN MADE TO THE ALLOCATION OF THE CAPACITY PORTION OF PURCHASED POWER AGREEMENTS?

A. In prior rate cases, the capacity portion of PPAs was stratified based on the generation type providing the energy, similar to how the Company stratifies generation plant. This was done to reflect the fact that capacity charges were typically higher for PPAs from generation plants with higher capital costs and lower energy costs. This stratification method would have allocated approximately 73 percent of the PPA capacity costs based on demand, and the remainder on energy.

However, in the current capacity market, all generation types are competing based on market price, such that capacity price does not vary significantly by resource type. In addition, the Company buys capacity based on its needs, not the underlying resource type. Therefore, the Company proposes to allocate 100 percent of the capacity costs based on demand, instead of stratifying and allocating the cost of the capacity according to the underlying generation type.

Q. MR. PEPPIN, HAS THE COMPANY PROVIDED ANY OTHER DOCUMENTS EXPLAINING HOW ITS CCOSS IS DEVELOPED?

A. Yes. The Company has provided a document titled "Guide to Class Cost of Service Study." This document is included with my testimony as Exhibit___(MAP-1), Schedule 2. It provides a primer on how the CCOSS was conducted, including the processes of cost functionalization, classification and allocation. These basic processes are common to all embedded cost studies. This Guide also describes how each of the cost allocation factors was developed and identifies the cost items to which each allocator is applied.

Q. PLEASE SUMMARIZE THE RESULTS OF THE PROPOSED CCOSS.

A. The following table provides a summary of the CCOSS results at the class level. More information is shown on Exhibit___(MAP-1), Schedule 3. The detailed CCOSS output is shown on Exhibit___(MAP-1), Schedule 4.

Table 1 below shows the resulting class cost responsibilities (as opposed to proposed revenue responsibilities, which are addressed by Mr. Huso). The CCOSS results indicate what change from present rates would be needed to generate equal rates of return on investment for each class (i.e. the increase in rates necessary to produce equalized rates of return).

Table 1
Summary of Class Cost of Service Study ($000)

UNADJUSTED COST RESPONSIBILITIES

		Total	Resid.	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 1)	199,597	75,923	12,283	109,241	2,150
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	26	20	2	4	0
[3]	Unadjusted Operating Revenues (line 1 + line 2)	199,623	75,943	12,285	109,245	2,150
[4]	Present Rates (CCOSS page 2, line 2)	182,724	70,465	11,575	98,825	1,860
[5]	Unadjusted Deficiency (line 3 - line 4)	16,899	5,478	710	10,420	290
[6]	Defic / Pres (line 5 / line 4)	9.2%	7.8%	6.1%	10.5%	15.6%
[7]	**Ratio: Class % / Total %**	**1.00**	**0.84**	**0.66**	**1.14**	**1.69**

CAPACITY COST RESPONSIBILITIES FOR INTERRUPTIBLE RATE DISCOUNTS

		Total	Resid	Non-Demand	Demand	Street Ltg
[8]	Interruption Rate Discounts (CCOSS page 2, line 5)	4,799	786	52	3,961	0
[9]	Interruption Capacity Costs (CCOSS page 2, line 6)	4,799	1,556	293	2,935	14
[10]	Revenue Requirement Shift (line 9 - line 8)	0	770	241	(1,025)	14

ADJUSTED COST RESPONSIBILITIES: TY 2013

		Total	Resid	Non-Demand	Demand	Street Ltg
[11]	Adjusted Rate Revenue Reqt (line 1 + line 10)	199,597	76,693	12,524	108,216	2,164
[12]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	26	20	2	4	0
[13]	Adjusted Operating Revenues (line 11 + line 12)	199,623	76,713	12,526	108,220	2,164
[14]	Present Rates (line 4)	182,724	70,465	11,575	98,825	1,860
[15]	Adjusted Deficiency (line 13 - line 14)	16,899	6,248	951	9,395	305
[16]	Defic / Pres Rates (line 15 / line 4)	9.2%	8.9%	8.2%	9.5%	16.4%
[17]	**Ratio: Class % / Total %**	**1.00**	**0.96**	**0.89**	**1.03**	**1.77**

Table 1 replicates Exhibit___(MAP-1), Schedule 3. Schedule 3 also provides, for comparison purposes, the class *revenue* allocations proposed by Mr. Huso.

Q. IN TABLE 1, YOU SHOW "ADJUSTED" AND "UNADJUSTED" COST RESPONSIBILITIES. PLEASE SUMMARIZE WHAT THIS DISTINCTION MEANS.

A. The distinction between "adjusted" and "unadjusted" cost responsibilities relates to how the "cost" of interruptible capacity is reflected in the CCOSS. The method used to reflect these costs is the same as that used in the Company's last general electric rate case, Case Nos. PU-10-657 and 11-55.

Unadjusted cost responsibilities are those that were historically used as the indicators of class cost responsibilities. However, as the size of the Company's interruptible programs grew, it became clear that these traditional unadjusted cost responsibilities did not properly account for the fact that interruptible rate discounts are essentially the "cost" of this particular source of generation peaking capacity. Therefore, the Company modified the CCOSS to produce adjusted cost responsibilities. The adjusted cost responsibilities appropriately account for the cost of this particular source of peaking capacity. Doing so is appropriate and important, because interruptible rate discounts (lost revenues) are a real cost of service arising from this particular alternative source of peaking capacity.

Q. PLEASE ELABORATE ON WHY INTERRUPTIBLE RATE DISCOUNTS ARE A COST OF GENERATION PEAKING CAPACITY.

A. As the Company indicated in previous rate cases, the economic essence of a utility's "obligation to serve" is to provide low-cost reliable firm electric service. Interruptible service is firm service with an after-the-fact purchased-power contract provision that provides the Company the option to buy back (from willing customers) all or part of their "regulatory entitlement" to firm service. The resulting capacity purchase transactions occur when, and if, doing so is a cost-effective source of peaking capacity, which helps the Company obtain a reliable power-supply portfolio at the lowest cost. This means interruptible rate discounts are essentially power-supply costs and must be recognized as such in the CCOSS.

Q. HOW DID YOU RECOGNIZE THIS COST IN THE CCOSS?

A. To accomplish this interruptible capacity cost accounting, the Company has added lines to the CCOSS model, as described below:

1. Line 8 on Table 1 above and Exhibit___(MAP-1), Schedule 3, labeled "Interruption Rate Discounts," shows the amount of the total interruptible discount originating from each class.
2. Line 9 on page Table 1 above and Exhibit___(MAP-1), Schedule 3, labeled "Interruption Capacity Cost," shows how this interruptible-capacity cost is allocated to the classes using the applicable generation capacity cost allocation factor.
3. The resulting Line 11 on Table 1 above and Exhibit___(MAP-1), Schedule 3, labeled "Adjusted Rate Revenue Requirement," shows the appropriate cost of service for determining class cost responsibilities.

Q. PLEASE EXPLAIN HOW THE RESULTS OF THE COMPANY'S PROPOSED CCOSS ARE USED IN DEVELOPING THE PROPOSED RATES.

A. The Company uses the proposed CCOSS as the basis for evaluating and refining its rate structure in a rate case. Mr. Huso uses it in this case as a guide in determining the proposed class revenue responsibilities, and for determining the proposed rate design for each tariff. The Company's proposed revenue allocation is provided on Exhibit___(MAP-1), Schedule 3, lines 18 through 23.

III. SELECTED RATE DESIGN REVISIONS: VOLTAGE DISCOUNTS

Q. WHAT REVISIONS DO YOU PROPOSE TO THE VOLTAGE DISCOUNTS THAT ARE A PART OF THE C&I DEMAND TARIFFS?

A. The results of the 2013 pro forma CCOSS indicates selected changes in the demand charge discounts are warranted (as shown on Exhibit___(MAP-1), Schedule 5, page 1, lines 4 and 6) to better reflect the cost of service. Also, as shown on Exhibit___(MAP-1), Schedule 5, page 2, columns 4 and 6, increases in energy charge discounts are also appropriate in order to move rates closer to the cost of service.

Table 2 below summarizes the cost analysis provided in Exhibit___(MAP-1), Schedule 5. The table compares the pro forma 2013 costs to the present and proposed voltage discounts.

Table 2
Voltage Discount Analysis

C&I Voltage Discounts – Demand ($/kW)			
Rate	**Primary**	**Transmission Transformed**	**Transmission**
Revenue Req	$0.52	$1.11	$1.58
Present	$0.62	$1.10	$1.40
Midpoint	$0.57	$1.10	$1.49
Proposed	$0.60	$1.10	$1.50
C&I Voltage Discounts – Energy (¢/kWh)			
Rate	**Primary**	**Transmission Transformed**	**Transmission**
Revenue Req	0.1015¢	0.2095¢	0.2373¢
Present	0.095¢	0.200¢	0.220¢
Proposed	0.102¢	0.210¢	0.240¢

IV. GENERAL RULES AND REGULATIONS

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE GENERAL RULES AND REGULATIONS IN SECTION 6 OF ITS NORTH DAKOTA ELECTRIC RATE BOOK?

A. The Company is proposing one wording change to Section 3.10 ACCOUNT HISTORY CHARGE to clarify how the Company defines an "Account" for this purpose, which also matches how the Company's cost analysis was conducted.

> *There shall be a charge of $5.00 per account <u>as defined by unique debtor and premise numbers</u> to the authorized requesting party for providing account history when such request involves ten or more ~~accounts~~ <u>premises</u>, regardless of the type of account or number of meters.*

V. CONCLUSION

Q. MR. PEPPIN, PLEASE PROVIDE A SUMMARY OF THE CONCLUSIONS FROM YOUR TESTIMONY.

A. The purpose of a CCOSS is to provide a reasonable measure of the contribution each class makes to the Company's overall cost of service, with the ultimate goal of generating a basis from which rates can be evaluated and refined. Based on the results of the CCOSS, the major customer classes have the following adjusted revenue deficiencies, stated as a percentage of present revenues:

- Residential Customers: 8.9 percent
- Commercial Non Demand Customers: 8.2 percent
- Commercial and Industrial Demand Billed Customers: 9.5 percent
- Lighting: 16.4 percent

The Company also proposes a clarifying change to its General Rules and Regulations, and changes to the Demand and Energy voltage discounts to move rates closer to the cost of service.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application of Northern States Power Company, a Minnesota Corporation For Authority to Increase Rates for Electric Service in North Dakota	))))	Case No. PU-12-___

AFFIDAVIT OF
Michael A. Peppin

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

Michael A. Peppin
Michael A. Peppin

Subscribed and sworn to before me, this 11th day of December, 2012.

____
Notary Public

CYNTHIA D. HARRINGTON
NOTARY PUBLIC
MINNESOTA
My Commission Expires Jan. 31, 2015

Statement of Qualifications and Experience

Michael A. Peppin

I graduated from the University of Minnesota, Twin Cities Campus, in 1978 with a Bachelor of Arts degree in Psychology, and in 1980 with a Master of Business Administration degree with an emphasis in Marketing and Statistics.

From October 1979 to December 2000, I was employed with Xcel Energy and its predecessor company Northern States Power Company ("NSP") in the positions of Principal Market Research Analyst (10 years), Market Research Manager (10 years) and Manager, Product Development Support (1½ years). In those positions, my responsibilities included conducting research to develop and evaluate NSP's Demand-Side Management programs, including NSP's interruptible and time-of-day rate programs. In January 2001, I accepted the position of Market Research Manager for Xcel Energy's unregulated broadband telecommunications subsidiary, Seren Innovations. My responsibilities involved research regarding the development, pricing and marketing of telecommunications products and services. With Xcel Energy's announced intention to sell Seren Innovations to external buyers, I accepted the position of Senior Market Research Manager with Cargill Corporation in February 2004. In that position, I conducted market research studies for many of Cargill's business units, including its Power Marketing unit. Finally, in December 2006, I resumed employment with Xcel Energy in the Pricing and Planning Department as a Principal Pricing Analyst.

My current job responsibilities include conducting Class Cost of Service Studies for various Xcel Energy jurisdictions and providing pricing function support for the utility operating subsidiaries of Xcel Energy.

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Guide to the Electric Class Cost of Service Study (CCOSS) Northern States Power Company

I. Overview

Simply stated, the purpose of the Northern States Power Company (NSP) electric Class Cost of Service (CCOSS) is to allocate ***joint*** (e.g.) and ***common*** costs to the designated "classes" of service such as Residential, Non-Demand C&I and Demand C&I. For example, generation capacity costs are "joint" between time periods, and overhead costs such as management are "common" to multiple functions, such as distribution, transmission and generation. The CCOSS also assigns ***direct*** costs (e.g. a dedicated service extensions or dedicated substations), that may be associated with providing service to a particular customer from a specific class of service. The objective of the CCOSS is to make these cost ***allocations*** and ***assignments*** based on identifiable service requirements (e.g. kWh energy requirements and kW capacity requirements), which are the drivers of the costs.

The two basic types of costs are; (1) capital costs associated with investment in generation, transmission and distribution facilities, and (2) on-going expenses such as fuel used to produce the energy, labor costs and numerous other operating expenses. The end result is an allocation of the total utility costs (i.e. the revenue requirements) to customer classes according to each class' share of the capacity, energy and customer service requirements.

II. Major Steps of the Class Cost of Service Study

A class cost of service study begins with a detailed documentation of the numerous budgetary elements of the total revenue requirement for the jurisdiction in question. The detailed jurisdictional revenue requirements are the data inputs to the CCOSS. At a high level, the CCOSS process consists of the following three (3) basic steps:

1. Functionalization – The identification of each cost element as one of the basic utility service "functions" (e.g. generation, transmission, distribution and customer).
2. Classification – The classification of the functionalized costs based on the billing component/determinant that each is associated with (e.g. kWs of capacity, kWhs of energy or number of customers).
3. Allocation – The allocation of the functionalized and classified costs to customer classes, based on each class' respective service requirements (e.g. kWs of capacity, kWhs of energy and the number of customers, expressed in terms of a percentage of the total jurisdiction requirement).

III. Step 1: Functionalization

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

Function	FERC Accounts	Sub-Function	Description
Generation	120, 310-346, 500-557	"Energy-related"	Includes the fixed costs of generation plant investment and purchase capacity costs, which have been stratified as "energy-related."
		Summer "capacity-related."	Includes the fixed costs of generation plant investment and purchase capacity costs stratified as "capacity-related" and which are associated with the system summer peak load requirements.
		Winter "capacity-related."	Includes the fixed costs of generation plant investment and purchase capacity costs stratified as "capacity-related" and which are associated with the system winter peak load requirements.
		On-Peak Energy	Includes costs for fuel and purchases of energy for on-peak hours.
		Off-Peak Energy	Includes costs for the fuel and purchases of energy for off-peak hours.
Transmission	350-359, 560-579	None	Includes costs of transmission lines used to transport power from its origin generation stations or delivery points to the high voltage side of the distribution substations.
Distribution	360-368, 580-598	Distribution Substations	Includes costs of the facilities (e.g. transformers and switch gear) between the transmission and distribution systems.
		Primary Distribution System "Capacity."	Includes costs of the "capacity" portion (as distinguished from the "customer" portion) of primary voltage conductors, transformers and related facilities.
		Secondary Distribution System "Capacity."	Includes costs of the "capacity" portion (as distinguished from the "customer" portion) of secondary voltage conductors, transformers, customer services and related facilities.
Customer	360-369, 580-598, 901-916	"Customer" portion of the Primary and Secondary Systems	Includes costs for the "customer" portion of primary and secondary conductors, transformers, customer service drops, related facilities and the costs of metering.
		Energy Services	Includes costs for meter reading, billing, customer service and information, and back office support.

A. Generation Cost Stratification

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

For example, the plant stratification analysis used in the current rate case is shown in the table below. It compares the current dollar replacement costs of each plant type to develop stratification percentages.

Plant Type	$/kW	Capacity Ratio	Capacity %	Energy %
Peaking	$689	$689 / $689	100%	0%
Nuclear	$3,678	$689 / $3,678	18.7%	81.3%
Fossil	$1,912	$689 / $1,912	36.0%	64.0%
Combined Cycle	$997	$689 / $997	69.1%	30.9%
Hydro	$4,474	$689 / $4,474	15.4%	84.6%
Wind	$15,297	$689 / $15,297	4.5%	95.5%

This process of "stratifying" the revenue requirements of the generation plant is accomplished by applying these stratification percents to each component of the revenue requirements (e.g. plant investment, accumulated depreciation, deferred income taxes, construction work in progress (CWIP), etc.) for each generation plant type.

B. Summer/Winter Split of Generation Capacity-Related Costs

Once the "capacity-related" portion of generation plant costs has been quantified, the costs are further separated into summer and winter sub-functions. The seasonal sub-function portions are determined as follows.

First, the 12 monthly System peak loads are grouped into a four-month summer (June, July, August and September) and an eight-month winter seasons. Second, the average hourly load for the year is subtracted from each monthly peak. Third, the remaining monthly excess loads are averaged for each season, and the ratio of these two average seasonal "excess" loads is used to assign the "capacity- related" portion of fixed generation costs to the seasons. This calculation for the current rate case is shown below.

(1)	(2)	(3)	(4) = (3) minus 5,066
Month	**Season**	**Monthly NSP System Peak Load**	**Monthly Peak in Excess of Average Hourly Load**
Jan	Winter	6,558	1,492
Feb	Winter	6,390	1,324
Mar	Winter	5,991	925
Apr	Winter	5,706	640
May	Winter	7,118	2,052
Jun	Summer	8,664	3,598
Jul	Summer	9,215	4,149
Aug	Summer	8,802	3,736
Sep	Summer	8,087	3,021
Oct	Winter	6,240	1,174
Nov	Winter	6,265	1,199
Dec	Winter	6,678	1,612
Average Annual Load		**5,066**	
Average Monthly Excess			
Average of Summer Months			3,626
Average of Winter Months			1,302
Total			**4,928**
Summer Percent			**73.58%** = 3,626/4,928
Winter Percent			**26.42%** = 1,302 /4,928

As shown above, 73.58% of generation capacity costs were assigned to the summer season, while 26.42% were assigned to winter, thereby separating total generation capacity-related costs into summer and winter seasons.

IV. Step 2: Cost Classification

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

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

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

Function/Sub-Function	**Cost Classification**		
	Demand	**Energy**	**Customer**
Summer Capacity-Related Fixed Generation	X		
Winter Capacity-Related Fixed Generation	X		
Energy-Related Fixed Generation		X	
Off-Peak Energy (Fuel and Purchased Energy)		X	
On-Peak Energy (Fuel and Purchased Energy)		X	
Transmission	X		
Distribution Substations	X		
Primary Transformers	X		
Primary Lines	X		X
Secondary Lines	X		X
Secondary Transformers	X		X
Service Drops	X		X
Metering			X
Customer Services			X

As shown in the table above, primary lines, secondary lines, secondary transformers and service drops are classified as both "demand" and "customer" related costs. Costs of these sub-functions are driven by **both** the number of customers on the distribution system and the capacity requirements they place on the system. The analysis used to separate these costs into demand and customer components is called the Minimum Distribution System (MDS) method.

The Minimum Distribution System method involves comparing the cost of the minimum size of each type of facility used, to the cost of the actual sized facilities installed. The cost of the minimum-size facilities determines the "customer" component of total costs, and the "capacity" cost component is the difference between total installed cost and the minimum-sized cost.

The table also shows the percent of each cost element that was classified as "customer" related based on the most recent Minimum System study.

Equipment Type	**% Classified as "Customer" Related**
Overhead Lines Primary	38.8%
Primary Transformers	0%
Overhead Lines Secondary	50.2%
Underground Lines Primary	83.0%
Underground Lines Secondary	52.5%
Line Transformers Secondary	45.6%
Services	72.7%

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

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

- Direct Assignment - A small but sometimes important portion of costs can be directly assigned to a specific customer of a particular customer class, because these costs can be exclusively identified as providing service to a particular customer. Examples of costs that are directly assigned include:
  - Customer-dedicated transmission radial lines or dedicated distribution substations
  - Street lighting facility costs
- Allocation - Most electric utility costs are incurred in common or jointly in providing service to all or most customers and classes. Therefore, allocation methods have to be developed for each functionalized and classified cost component. The allocation method is based on the particular measures of service that is indicative of what drives the costs.
  - Class allocators (sometimes called allocation strings) are simply a "string" of class percentages that sum to 100%.
  - There are 2 types of allocators:
    - External Allocators – These are the more interesting allocators that are based on data from outside the CCOSS model (e.g. load research data, metering and customer service-related cost ratios). In general, there are three types of external allocators:
      - Capacity –related (sometimes referred to as Demand) allocators such as:
        - System coincident peak (CP) responsibility or class contribution to system peak (1CP, 4CP or 12CP)
        - Class peak or non-coincident peak
        - Individual customer maximum demands
      - Energy-related allocators such as:
        - kWh at the customer (kWh sales)
        - kWh at the generator (kWh sales plus loses)
        - kWh energy, weighted by the variable cost of the energy in the hour it is used
      - Customer-related allocators
        - Number of customers
        - Weighted number of customers, where the weights are based on cost of meters, billing, meter-reading, etc.

      Details on the external allocators used in the CCOSS model are shown in Appendix 1.

    - Internal Allocators – These are allocators based on combinations of costs already allocated to the classes using external allocators. These internal allocators are used to assign certain costs, which are most appropriately associated with and assigned to classes by some combination of other primary service requirements, such as kWs demand, kWhs of energy or the number of customers. Examples of internal allocators include:
      - Production, transmission and distribution plant investment – Labeled "PTD" in the CCOSS model.

- Distribution O&M expenses without supervision and miscellaneous expenses – Labeled "OXDTS" in the CCOSS model.

Details on the development of the internal allocators used in the CCOSS model are shown in Appendix 2.

VI. Customer Class Definitions

Ideally, there would be no customer class groupings and cost allocation would reflect the unique costs of each individual customer. Because this is not possible, it is necessary to develop a cost study process that identifies costs of service for groups of customers ("classes") where the customers of the class have similar cost/service characteristics. The basic classes of service employed in the Company's CCOSS are the following:

1. Residential
2. Non Demand Metered Commercial
3. Demand Metered Commercial & Industrial
4. Street & Outdoor Lighting

Also, because of the significantly different distribution-functional requirements of customers within the Demand Metered C&I class, the Company's CCOSS also identifies the cost differences associated with the following distribution-function requirements within this class based on the voltage they are served at:

1. Secondary
2. Primary
3. Transmission Transformed
4. Transmission

More detail on customer class definitions is shown in Appendix 3.

VII. Organization of the CCOSS Model

The CCOSS model consists of numerous worksheets which show costs by customer class in Total (as shown on the worksheet tab labeled "TOT") and at the following more detailed levels including Billing Unit, Function and Sub-function as shown below (the label of the worksheet tab in shown in parenthesis below):

1. Billing Unit:

   a. Customer (Cus)
   b. Demand (Dmd)
   c. Energy (Ene)

2. Function and Associated Sub-Function:

   a. Energy (Ene)
      a) On-Peak Energy (On)
      b) Off-Peak Energy (Off)

   b. Generation (Gen_Dmd): Sub-functions include:

a) Summer Capacity-Related Plant (Summ)
b) Winter Capacity-Related Plant (Wint)
c) Energy-Related Plant (Base)

c. Transmission (Transco)

d. Distribution (Disco): Sub-functions include:
a) Distribution Substations (Psub)
b) Primary Voltage (Prim)
c) Secondary Voltage (Sec)

e. Customer (Cus): Sub-functions include:
a) Service Drops (Svc_Drop)
b) Energy Services (En_Svc)

In the CCOSS spreadsheet, there is a separate worksheet tab for each of the above billing units, functions and sub-functions. This multi-level breakdown of costs is useful for designing rates as well as for determining class revenue responsibilities.

VIII. CCOSS Calculations

Listed below are important calculations that are part of the CCOSS model. These calculations occur at the "TOT" layer of the CCOSS as well as each of the "sub-layers" for each billing component, function and sub-function. Showing results at the more detailed billing component, function and sub-function levels is important for rate design purposes, as well as other analyses such as the development of voltage discounts.

A. Rate Base Calculation

Rate Base = Original Plant in Service – Accum. Depr + CWIP + Other Additions

The above rate base calculation occurs on "TOT" layer as well as each function/sub function layer.

B. Revenue Requirements Calculation (Class Cost Responsibility)

The Revenue Requirements Calculation (sometimes referred to as the "Backwards Revenue Requirement Calculation) is used to calculate "**cost**" responsibility for each customer class. This has to be done within the CCOSS model, because the JCOSS model does it only at the total jurisdiction level, not by class. The class "**cost**" responsibility is based on the same return on rate base for each class that is equal to the overall proposed rate of return. In other words, class revenues requirements are calculated to provide the same return on rate base for each customer class. This calculation occurs on the "TOT" layer as well as for each function, sub-function and billing component after all expenses and rate base items have been allocated. As such, class cost responsibility is available for each function, sub-function and billing component. This analysis serves a starting point for rate design. The formula is shown below:

Retail Revenue Requirement = Expenses (including off-setting credits from Other Operating Revenues)
+
(Return on Equity x Rate Base) x 1 / (1-Tax Rate)
+
(Tax Additions – Tax Deductions) x Tax Rate / (1-Tax Rate)
+
AFUDC

Where:

Expenses = O&M + Book Depreciation + Real Estate & Property Tax + Payroll Tax + Net Investment Tax Credit – Other Retail Revenue – Other Operating Revenue

Tax Additions = Book Depreciation + Deferred Inc Tax + Net Inv Tax Credit + Other Misc Expenses

Tax Deductions = Tax Depreciation + Interest Expense + Other Tax Timing Diff

C. Total Return and Return on Rate Base (Based on Class Revenue Responsibility)

After rates have been designed and each class' "**revenue**" responsibility has been determined, the model calculates total return and return on rate base using the following formulas. These calculations are performed at both present and proposed rate levels.

Total $ Return = Revenue – O&M Expenses – Book Depreciation
– Real Estate & Property Taxes– Provision for Deferred Inc Taxes – Inv. Tax Credits
– State & Federal Income Taxes + AFUDC

Percent Return on Rate Base = Total $ Return / $ Rate Base

After rates have been designed, the return on rate base is typically different for each customer class. In other words, the resulting class "**revenue**" responsibility differs from class "**cost**" responsibility.

IX. CCOSS Output

The filed output of the CCOSS model includes the "Tot" worksheet layer of the much larger model. The important output from the functional, sub-functional and billing component layers is presented on pages 2 and 3 of this "TOT" layer. The following table lists what is shown on each CCOSS page when printed.

Final CCOSS Printout "Tot" Worksheet			
CCOSS Section	**Page Number**	**Results Detail**	**Line Numbers**
Results Summary	1	Rate Base Summary	1-21
		Income Statement Summary	22-31
	2	**Proposed Cost** Responsibility at Equal ROR (the cost of service) compared to **Present** Rate **Revenue** Responsibility	1-49
	3	**Proposed Cost** Responsibility at Equal ROR (the cost of service) compared to **Proposed** Rate **Revenue** Responsibility	1-52
Rate Base Detail	4	Original Plant in Service	1-48
	5	MINUS Accumulated Depreciation	1-30
		MINUS Accumulated Deferred Income Tax	31-59
	6	PLUS Construction Work in Progress & Other Additions	1-35
		EQUALS Total Rate Base	36
Income Statement Detail	7	Present and Proposed Revenues	1-26
		MINUS O&M Expenses part 1	27-41
	8	MINUS O&M Expenses part 2	1-34
	9	MINUS Book Depreciation	1-25
		MINUS Real Estate & Property Taxes	26-53
	10	MINUS Provision for Deferred Income Tax	1-28
		MINUS Investment Tax Credit	29-49
		EQUALS Present and Proposed Operating Income Before Income Taxes	51A 51B
	11 (Income Tax Calcs.)	Tax Additions	31-37
		MINUS Tax Deductions	1-30
		EQUALS Total Tax Adjustments	38
		PLUS Present and Proposed Operating Income Before Income Taxes	FROM Page 10 51A 51B
		EQUALS Present and Proposed Taxable Income	39A 39B
		MULTIPLIED BY State and Federal Tax Rates	
		EQUALS Present and Proposed State and Federal Income Taxes	40A 40B
	11 (Total Return Calcs.)	Present and Proposed Operating Income Before Income Taxes	FROM Page 10, Rows 51A & 51B
		MINUS Present and Proposed State and Federal Income Taxes	40A 40B
		EQUALS Present and Proposed Preliminary Return	41A 41B
		PLUS AFUDC (from page 12)	42
		EQUALS Present and Proposed Total Return	43A 43B

IX. CCOSS Output (continued)

CCOSS Section	Page Number	Results Detail	Line Numbers
Misc Calcs	12	AFUDC	1-26
		Labor Allocator	27-48
Allocator Data	13	Internal Allocators and Associated Data	1-30
	14	External Allocators and Associated Data	1-41

Appendix 1: EXTERNAL ALLOCATORS – Descriptions and Applications

The table below lists and describes the external allocators used in the Class Cost of Service (CCOSS) model.

Code	Allocator For:	Description	Allocator Rationale and Background
C11	**Connection charge revenues**	**Average monthly customers for the Test Year**	**Customer connection revenues are driven by number of customer services.**
C10	Used to calculate C11	C11 less automatic protective lighting and load management services. C11 less number of customers with a second service.	
C11WAF	Used to calculate C11WA allocator	Customer accounting cost weighting factors. The weighting factor for residential customers is set at 1.0. The weighting factors for other classes are defined relative to costs for residential. E.g., if a class were three times costlier, its factor would be 3.0.	Weighting factors are set so as to reflect the relative costs of meter reading, billing and providing customer service for different classes of customers. For example some rate schedules are significantly more complex requiring more sophisticated meter reading capabilities, billing systems and customer service staff.
C11WA	**Customer accounting costs**	**Average monthly customers weighted by each class' relative rating of customer accounting costs: C11 X C11WAF**	**Customer accounting costs are driven by number of customers and the complexity of their respective rate, billing issues and customer service requirements.**
C12	Used to calculate C12WM allocator	Reflects actual number of meters. C11 with an adjusted street lighting customer count. Only selected street lighting rates are metered	
C12WMF	Used to calculate C12WM allocator	Average meter cost for each customer type	
C12WM	**Meter costs**	**Number of meters multiplied by each class' average meter costs: C12 X C12WMF**	**Metering costs are driven by the number of customers in each class and the respective metering costs.**
C61PS	**The "customer" (minimum system) portion of primary distribution line costs**	**Average monthly customers served at primary or secondary voltage. C11 less transmission transformed and transmission voltage customers**	**The number of customers served at secondary and primary voltages drives the customer-related portion of primary distribution line costs. Transmission and Transmission Transformed voltage customers are excluded since they do not use the distribution system**

Appendix 1: EXTERNAL ALLOCATORS – Descriptions and Applications

Code	Allocator For:	Derivation	Allocator Rationale and Background
C62Sec	**The "customer" (minimum system) portion of secondary (not primary) distribution line costs**	**Average monthly customers served at secondary voltage. C61PS less primary voltage customers**	**The number of customers served at secondary voltage drives the customer related portion of <u>secondary distribution line</u> costs. Transmission and primary voltage customers are excluded since they do not use the secondary distribution system.**
C62NL	**The "customer" (minimum system) portion of <u>service-line</u> costs.**	**Adjusted average monthly secondary voltage customers. C62Sec less street lighting and C&I underground customers**	**The number of secondary customers drives the customer portion of <u>service line</u> costs. C&I underground secondary customers are excluded since they own their services. Lighting customers are excluded since they do not have services.**
D60Sub	**Distribution substation costs**	**Class Coincident peak measured at the high voltage side of the Distribution Substation less Class Coincident peak of Transmission Voltage customers**	**<u>Distribution substation</u> costs are driven by class peak demands, whenever they occur which is generally at times other than the total system peak. Transmission voltage customers are excluded since they do not use the distribution substation.**
D61PS	**The <u>capacity</u> portion of <u>primary</u> distribution line costs.**	**D60Sub less Transmission Transformed customer demands, less customer demands served by minimum distribution system and with reduced Residential Space Heating demands to reflect the fact that their summer peak is less than their winter peak.**	**The driver <u>of primary distribution line</u> costs is the class coincident demands less the minimum system demand of each class. The minimum demand is classified as a customer related cost. Also transmission and transmission transformed voltage customers are excluded since they do not use the distribution system.**
D62Sec	Used to calculate the D62SecL allocator	D61PS less class coincident demands of primary voltage customers	
D62SecL	**The <u>capacity</u> portion of <u>secondary</u> distribution line costs**	**D62SecL equals the average of D62Sec percent and non-coincident (or "individual customer peak") secondary voltage percent.**	**Capacity related <u>secondary distribution line</u> costs are driven by both class coincident peak demand and individual customer maximum demand, less the minimum system demand of each class. (The minimum system demand is classified as customer related.) Also, transmission and primary voltage customers are excluded since they do not use the secondary distribution system.**

Appendix 1: EXTERNAL ALLOCATORS – Descriptions and Applications

Code	Allocator For:	Derivation	Allocator Rationale
D62NLL	The capacity portion of service-line costs	Non-coincident (or "customer peak") demand for secondary voltage customers, less the customer peak demand for street lighting, area lighting and C&I customers served underground	Capacity related service line costs are driven by individual customer maximum demands less the minimum system demand of each class. (The minimum system demand is customer related.) Transmission voltage, primary voltage and lighting customers are excluded since they do not cause service related costs. Also excluded are C&I underground customers since they install their own services.
D10S	Summer season portion of capacity-related generation costs	Each class' % contribution to the single summer system peak. Summer months are June through September.	The class contribution to the system summer peak drives the summer portion of capacity-related generation costs.
D10W	Winter season portion of capacity-related generation costs	Each class' % contribution to the single winter system peak. Winter months are October through May.	The class contribution to the system winter peak drives the winter portion of capacity-related generation costs.
D10T	Transmission plant costs	Weighted Class Contributions to Summer and Winter Peak loads. Allocator equals (D10W% plus (D10S% times 1.3649)) divided by (1 + 1.3649). The 1.3649 ratio is the ratio of the average summer and winter seasonal system peaks.	The driver for transmission costs is class contribution to the summer and winter system peaks. To reflect the fact that summer peaks have more impact, the summer peak contribution for each class is weighted by the ratio of average monthly summer and average monthly winter system peaks.
D10C	Capacity-related generation costs	Weighted of Class Contributions to Summer and Winter system peak loads. Allocator equals (D10W% plus (D10S% times 2.7846) divided by (1 + 2.7846). The 2.7846 ratio is obtained from the average summer and winter season peak loads, after subtracting the average annual load from each monthly load.	Capacity- related generation costs are driven by class contribution to summer & winter system peaks. To reflect the fact that summer peaks have a disproportionate impact on capacity-related generation costs, the summer peak is weighted by the ratio of average monthly summer and winter system peaks, which are in excess of average annual demand.

Appendix 1: EXTERNAL ALLOCATORS – Descriptions and Applications

Code	Allocator For:	Derivation	Allocator Rationale
E8760	**Energy-related portion of generation, nuclear fuel capital and generation step-up costs. Also allocator for fuel, purchased energy and energy-related fixed generation costs.**	**Class hourly energy (MWH) requirements multiplied by the corresponding hourly marginal energy cost.**	**The driver of these costs is energy requirements, which is measured by hourly energy requirements weighted by hourly marginal energy costs.**

Appendix 2: INTERNAL ALLOCATORS – Descriptions and Applications

Internal Allocators are those that are determined from data generated within the Class Cost of Service Study (CCOSS). Below is a list of internal allocators that are used within the CCOSS.

Code	Allocator For:	Description	Allocator Rationale
C11P10	Expenses and labor related to customer assistance and instructional advertising	This allocator is the average of the Customer-related C11 allocator and the Production Plant investment P10 allocator.	Customer assistance and advertising expenses are driven by number of customers, and since most assistance pertains to helping customers reduce energy use, it affects production plant investment.
D57E43	Economic development expenses	This allocator is based on the weighted average of the generation capacity and energy allocators. The weighting is based on an analysis of the fixed-cost-contribution margin of the General service tariff. D57E43 = (% Demand Impacts x D10C) + (% Energy Impacts x E8760). $ Energy Impacts = kWh sales x (Base Energy Charge + Fuel Costs – Marginal Energy Costs) $ Demand Impacts = Annual Billing kW x (((4 x Summer Demand Charge)+ (8 x Winter Demand Charge))/12) The demand portion is further split between Summer and Winter based on D10C; the energy portion is already split between on-peak and off-peak because E8760 is split that way. Total $ Impacts = $ Energy Impacts + $ Demand Impacts	Economic development program costs and benefits are assumed to be a function of the fixed cost (margin) contribution of the demand and energy charges that result from the ED program.
D40E60	CIP expenses	D99E1 = (.99 x D10C)+(.01 x E8760).	CIP program expenses are split between capacity and energy according to whether the purpose and result of program is to reduce peak load or energy requirements. In North Dakota, 99% of program impacts are demand-related. Once program costs are thus split, the standard capacity and energy allocators are applied to the separate pools of $ expenses.

Appendix 2: INTERNAL ALLOCATORS – Descriptions and Applications

Code	Allocator For:	Description	Allocator Rationale
LABOR	Amortizations, Payroll Taxes and A&G Expenses that are labor related such as Salaries, Pension & Benefits, Injuries & Claims	Total Labor costs on Page 12 line 48 less A&G Labor on Page 12 line 46. A&G Labor is excluded to avoid a circular reference.	The specified expenses are directly related to Labor costs.
NEPIS	Property Insurance	Electric plant in service less accumulated provision for depreciation.	Property insurance is driven by net electric plant in service.
OXDTS	Distribution customer installation expenses and miscellaneous distribution expense	All Distribution O&M Expense, except Supervision and Engineering, Customer Install and Miscellaneous. Supervision and engineering expenses are excluded since they are an overhead expense. Customer installation expenses and miscellaneous distribution expense are excluded to avoid a circular reference. (lines 2 thru 7, 9 and 11 of page 8)	The OXDTS allocator represents the majority of Distribution O&M expenses (excl supervision and customer installation costs) which is a good indicator for miscellaneous distribution expenses.
OXTS	Selected administrative and general expenses such as Office Supplies, General Advertising, Contributions and maintenance of "General" plant	All O&M costs except Regulatory Expense and any A&G costs, which are the costs to be allocated on OXTS (lines 40 & 41 of page 7 and lines 12-15, 18-21, 32 and 33 of page 8). These A&G expenses are excluded to avoid circular references.	The OXTS allocator includes all O&M expenses except regulatory expense and those A&G items that are allocated with OXTS. Representing most O&M expenses, the OXTS allocator is appropriate for allocating A&G expenses.
P10	Interchange Production Capacity (i.e. fixed) inter-company Revenues. Rate base addition production-related materials and supplies	Total Production Plant: Original Plant in Service (line 6 of page 4)	Total production plant investment is closely associated with Interchange Agreement Capacity related revenues.
P10WoN	Interchange Production Capacity (i.e. fixed) inter-company costs	Total Production Plant less Nuclear Fuel: Original Plant in Service. Nuclear fuel is excluded since NSP Wisconsin does not have nuclear plants (Total Production Plant on line 6 of page 4 less Nuclear Fuel on line 5 of page 4)	Since Wisconsin does not have nuclear plants, Total production plant investment less nuclear fuel investment is a good indicator of Interchange Agreement Capacity related expenses.
P5161A	Used to allocate Step-up sub transmission labor costs	Total Generation Set-Up Transformer original plant in service: Tran Gener Step Up (line 9 of page 4) + Distrib Substn Step Up (line 14 of page 4)	Generation step-up plant investment drives step-up generation labor costs.
P61	Distribution Substation O&M expense and Distribution Substation labor	Distribution Plant: Substations Original Plant in Service (line 18, page 4)	Substation plant original investment drives Distribution Substation plant O&M costs and Distribution Substation Labor.

Appendix 2: INTERNAL ALLOCATORS – Descriptions and Applications

Code	Allocator For:	Derivation	Allocator Rationale
P68	All costs related to Distribution Plant "Line Transformers"	Distribution Plant: Line Transformers Original Plant in Service (line 37 of page 4)	Line transformer plant investment drives all line transformer costs.
P69	All costs related to Distribution Plant "Services"	Customer-Connection "Services" Original Plant in Service (line 40 of page 4)	Distribution "Services" plant investment drives all costs of "Services".
P73	All costs related to Street Lighting	Street Lighting Original Plant in Service (line 42 of page 4)	Street Lighting plant investment drives all Street Lighting costs.
POL	All costs related to Overhead Distribution Lines including Rental costs and Distribution overhead line rent revenues	Distribution Plant: Overhead Lines Original Plant in Service (line 26 of page 4)	Overhead distribution line plant investment drives all costs related to Overhead Distribution Lines.
PT0	Working Cash	Total Real Estate & Property Taxes (line 50 of page 9)	Working Cash is closely related to Real Estate Taxes.
PTD	All costs related to General Plant and Electric Common Plant	Production + Transmission + Distribution Plant Original Plant Investment (lines 6, 13 and 43 of page 4)	Total investment in production, transmission and distribution plant is the best allocator for general and common plant.
PUL	All costs related to Underground Distribution Lines	Distribution Plant: Underground Lines Original Plant in Service (line 33 of page 4)	Underground distribution line plant investment drives all costs related to Underground Distribution Lines.
RTBASE	Income Tax Addition: Avoided tax interest	Total Rate Base (line 36 of page 6)	Total rate base drives avoided tax interest.
TD	Transmission and Distribution Materials and Supplies that are Rate Base Additions	Total Transmission and Distribution Original Plant in Service (Lines 13 and 43 of page 4)	Total Transmission and distribution plant investment drives investment in miscellaneous transmission and distribution materials and supplies
ZDTS	Supervision & Engineering and Customer Installation Distribution Labor	All Distribution Labor except Supervision and Engineering and Customer Installation. These items are excluded to avoid a circular reference. (All of lines 33 thru 42 on page 12, except lines 33 and 40)	Distribution labor (excluding Supervision & Engineering) drives Supervision and Engineering and Customer Installation Labor.

Appendix 3: CCOSS Customer Classes Vs. Tariff Cross Reference

A. Summary Customer Classes

	Customer Class	Rate Codes	Voltage Specifications
1	Residential	D01, D02, D03, D04, D05 (if residential), D10 (if residential)	
2	Commercial Not Demand Metered	D05 (if C&I), D10 (if C&I), D12, D14, D15, D18, D19, D34, D40, D42	
3	C&I Secondary Voltage	D16, D17, D20, D21, D22, D41, D62, D63	Secondary
4	C&I Primary Voltage	D16, D17, D20, D21, D22, D41, D62, D63	Primary
5	Street Lighting	D11, D30, D31, D32, D33	

B. Detailed Customer Sub-Classes

	Customer Class	Rate Codes	kW Size	Voltage Specifications
1	Residential without Space Heating	D01, D02, D03, D04		
2	Residential with Space Heating	D01, D02, D03, D04		
3	Load Management	D05, D10		
4	Small Commercial Not Demand Metered	D12, D14, D15, D18, D19, D34,		
5	Small C&I Secondary Voltage	D16, D17, D62	< 1,000 kW	Secondary
6	Small C&I Primary Voltage	D16, D17, D62	< 1,000 kW	Primary
7	Large C&I Secondary Voltage	D16, D17, D62	> 1,000 kW	Secondary
8	Large C&I Primary Voltage	D16, D17, D62	> 1,000 kW	Primary
9	Interruptible All Voltages	D20, D21, D22, D63	All sizes	All Voltages
10	Municipal not Demand Metered	D40, D42		
11	Municipal Demand Metered	D41		
12	Auto Protective Lighting	D11		
13	Street Lighting – Company Owned	D30		
14	Street Lighting – Customer Owned	D31, D32, D33		

Northern States Power Company
Electric Utility - State of North Dakota
Test Year Ending December 31, 2013
Summary of Class Cost of Service Study Results ($000)

Case No. PU-12-____
Exhibit___(MAP-1), Schedule 3
Page 1 of 1

UNADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[1]	Unadjusted Rate Revenue Reqt (CCOSS page 2, line 1)	199,597	75,923	12,283	109,241	2,150
[2]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	26	20	2	4	0
[3]	Unadjusted Operating Revenues (line 1 + line 2)	199,623	75,943	12,285	109,245	2,150
[4]	Present Rates (CCOSS page 2, line 2)	182,724	70,465	11,575	98,825	1,860
[5]	Unadjusted Deficiency (line 3 - line 4)	16,899	5,478	710	10,420	290
[6]	Defic / Pres (line 5 / line 4)	9.2%	7.8%	6.1%	10.5%	15.6%
[7]	**Ratio: Class % / Total %**	**1.00**	**0.84**	**0.66**	**1.14**	**1.69**

CAPACITY COST RESPONSIBILITIES FOR INTERRUPTIBLE RATE DISCOUNTS

		Total	Residential	Non-Demand	Demand	Street Ltg
[8]	Interruption Rate Discounts (CCOSS page 2, line 5)	4,799	786	52	3,961	0
[9]	Interruption Capacity Costs (CCOSS page 2, line 6)	4,799	1,556	293	2,935	14
[10]	Revenue Requirement Shift (line 9 - line 8)	0	770	241	(1,025)	14

ADJUSTED COST RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[11]	Adjusted Rate Revenue Reqt (line 1 + line 10)	199,597	76,693	12,524	108,216	2,164
[12]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	26	20	2	4	0
[13]	Adjusted Operating Revenues (line 11 + line 12)	199,623	76,713	12,526	108,220	2,164
[14]	Present Rates (line 4)	182,724	70,465	11,575	98,825	1,860
[15]	Adjusted Deficiency (line 13 - line 14)	16,899	6,248	951	9,395	305
[16]	Defic / Pres Rates (line 15 / line 4)	9.2%	8.9%	8.2%	9.5%	16.4%
[17]	**Ratio: Class % / Total %**	**1.00**	**0.96**	**0.89**	**1.03**	**1.77**

PROPOSED REVENUE RESPONSIBILITIES

		Total	Residential	Non-Demand	Demand	Street Ltg
[18]	Proposed Rates (CCOSS page 3, line 3)	199,597	76,777	12,537	108,334	1,948
[19]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line 23)	26	20	2	4	0
[20]	Proposed Operating Revenues (line 18 + line 19)	199,623	76,797	12,539	108,338	1,948
[21]	Proposed Increase (line 20 - line 14)	16,899	6,332	964	9,514	89
[22]	Difference / Pres (line 21 / line 14)	9.2%	9.0%	8.3%	9.6%	4.8%
[23]	**Ratio: Class % / Total %**	**1.00**	**0.97**	**0.90**	**1.04**	**0.52**

Northern States Power Company
Electric Utility - State of North Dakota
Test Year Ending 31 Dec 2013
Proposed Class Cost of Service Study Detail

Case No. PU-12-____
Exhibit___(MAP-1)
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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**	**Ltg**
1	Production		537,079	182,835	351,311	31,299	320,012	282,259	37,753	0	0	2,932
2	Transmission		136,211	46,201	89,352	8,420	80,933	72,379	8,554	0	0	658
3	Distribution		138,687	86,921	47,040	9,889	37,151	34,385	2,766	0	0	4,726
4	General		29,097	11,322	17,477	1,778	15,699	13,941	1,759	0	0	298
5	Common		29,899	11,634	17,958	1,827	16,132	14,325	1,807	0	0	306
6	Total Plant In Service		870,972	338,913	523,139	53,213	469,926	417,288	52,638	0	0	8,920
7	Production		289,499	98,849	189,025	16,820	172,204	151,752	20,452	0	0	1,625
8	Transmission		38,787	13,156	25,444	2,395	23,048	20,608	2,441	0	0	188
9	Distribution		62,947	39,210	21,019	4,418	16,601	15,374	1,227	0	0	2,718
10	General		11,053	4,301	6,639	675	5,964	5,296	668	0	0	113
11	Common		17,303	6,733	10,393	1,057	9,336	8,290	1,046	0	0	177
12	Total Depreciation Reserve		419,589	162,248	252,519	25,367	227,153	201,319	25,833	0	0	4,822
13	**Net Plant In Service**		451,383	176,665	270,619	27,846	242,773	215,969	26,805	0	0	4,099
14	Deducts: Accum Defer Inc Tax		92,784	37,188	54,845	5,733	49,112	43,678	5,434	0	0	750
15	Constr Work In Progress		2,037	704	1,321	121	1,200	1,063	136	0	0	12
16	Fuel Inventory		5,899	2,040	3,822	338	3,484	3,058	426	0	0	37
17	Materials & Supplies		7,613	2,756	4,800	453	4,347	3,845	502	0	0	58
18	Prepayments		6,235	2,440	3,738	385	3,353	2,983	370	0	0	57
19	Non-Plant & Work Cash		(2,735)	(1,068)	(1,633)	(172)	(1,461)	(1,298)	(163)	0	0	(34)
20	Total Additions		19,049	6,872	12,048	1,126	10,923	9,651	1,271	0	0	129
21	**Rate Base**		377,648	146,349	227,822	23,238	204,584	181,942	22,642	0	0	3,477

Income Statement

			MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	Ltg
22A	**Tot Oper Rev - Pres**		228,226	86,378	139,717	14,260	125,457	112,173	13,285	0	0	2,131
22B	**Tot Oper Rev - Prop**		245,125	92,710	150,195	15,224	134,971	120,704	14,266	0	0	2,220
22C	**Tot Oper Rev - Equal**		245,125	91,856	150,848	14,970	135,878	120,266	15,611	0	0	2,422
23	Oper & Maint		170,097	62,169	106,315	10,332	95,982	84,776	11,206	0	0	1,614
24	Book Depr + IRS Int		22,563	9,095	13,192	1,390	11,802	10,498	1,304	0	0	276
25	Payroll, Rl Est & Prop Tax		9,871	3,912	5,845	615	5,230	4,656	573	0	0	114
26	Deferred Inc Tax & Net ITC		12,760	4,373	8,310	766	7,545	6,684	861	0	0	77
27A	Present Income Tax		(6,481)	(1,355)	(5,081)	(242)	(4,839)	(3,824)	(1,015)	0	0	(45)
27B	Proposed Income Tax		(1)	1,073	(1,063)	128	(1,191)	(553)	(638)	0	0	(11)
27C	Equal Income Tax		(0)	746	(813)	30	(843)	(721)	(123)	0	0	67
28	Allow Funds Dur Const		0	0	0	0	0	0	0	0	0	0
29A	**Present Return**		19,416	8,184	11,136	1,398	9,738	9,383	354	0	0	96
29B	**Proposed Return**		29,834	12,088	17,596	1,992	15,603	14,643	960	0	0	150
29C	**Equal Return**		29,834	11,562	17,998	1,836	16,162	14,373	1,789	0	0	275
30A	**Pres Ret on Rt Base**		5.14%	5.59%	4.89%	6.02%	4.76%	5.16%	1.56%	0.00%	0.00%	2.75%
30B	**Prop Ret on Rt Base**		**7.90%**	8.26%	7.72%	8.57%	7.63%	8.05%	4.24%	0.00%	0.00%	4.33%
31A	**Pres Ret on Common**		5.35%	6.21%	4.87%	7.01%	4.62%	5.38%	-1.46%	0.00%	0.00%	0.81%
31B	**Prop Ret on Common**		**10.60%**	11.28%	10.26%	11.88%	10.08%	10.88%	3.63%	0.00%	0.00%	3.80%

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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**	**Ltg**
1	**UnAdj Equal Rev Reqt @ 7.90%**		**199,597**	**75,923**	**121,524**	**12,283**	**109,241**	**96,743**	**12,499**	**0**	**0**	**2,150**
2	**Present Revenue**		**182,724**	**70,465**	**110,400**	**11,575**	**98,825**	**88,653**	**10,172**	**0**	**0**	**1,860**
3	**UnAdj Revenue Deficiency**		**16,873**	**5,458**	**11,125**	**708**	**10,416**	**8,090**	**2,326**	**0**	**0**	**290**
4	**UnAdj Deficiency / Present**		**9.23%**	**7.75%**	**10.08%**	**6.12%**	**10.54%**	**9.13%**	**22.87%**	**0.00%**	**0.00%**	**15.61%**
5	**Pres Interrupt Rate Discounts**		**4,799**	**786**	**4,013**	**52**	**3,961**	**2,829**	**1,132**	**0**	**0**	**0**
6	**Pres Interrupt Capacity Costs**	D10C	**4,799**	**1,556**	**3,228**	**293**	**2,935**	**2,625**	**310**	**0**	**0**	**14**
7	**Revenue Shift**		**0**	**770**	**(784)**	**241**	**(1,025)**	**(204)**	**(821)**	**0**	**0**	**14**
8	**Adj Equal Rev Reqt (Rows 1+7)**		**199,597**	**76,693**	**120,740**	**12,524**	**108,216**	**96,539**	**11,677**	**0**	**0**	**2,164**
9	**Adj Rev Defic vs Pres Rev (Row 2)**		**16,873**	**6,228**	**10,341**	**950**	**9,391**	**7,886**	**1,505**	**0**	**0**	**305**
10	**Adj Deficiency / Adj Present**		**9.23%**	**8.84%**	**9.37%**	**8.20%**	**9.50%**	**8.90%**	**14.79%**	**0.00%**	**0.00%**	**16.38%**
	Equal Customer Classification											
11	Min Sys & Service Drop		11,666	8,926	1,640	1,024	617	593	23	0	0	1,100
12	Energy Services		5,236	4,173	1,038	619	419	413	5	0	0	25
13	Total Customer **(Cusco)**		16,902	13,099	2,678	1,643	1,035	1,007	29	0	0	1,125
14	Ave Monthly Customers		91,774	77,450	12,459	8,812	3,648	3,614	33	0	0	1,865
15	Svc Drop Reqt	$ / Mo / Cust	$10.59	$9.60	$10.97	$9.68	$14.09	$13.68	$58.24	$0.00	$0.00	$49.16
16	Ener Svcs Reqt	$ / Mo / Cust	$4.75	$4.49	$6.94	$5.86	$9.56	$9.53	$12.95	$0.00	$0.00	$1.10
17	Total Reqt	$ / Mo / Cust	$15.35	$14.09	$17.91	$15.54	$23.65	$23.21	$71.20	$0.00	$0.00	$50.26
	Equal Energy Classification											
18	On Peak Rev Reqt		52,595	16,508	35,962	3,402	32,560	28,733	3,827	0	0	125
19	Off Peak Rev Reqt		47,787	18,142	29,140	2,355	26,785	23,362	3,423	0	0	506
20	Total Ener Rev Reqt		100,382	34,650	65,102	5,757	59,345	52,095	7,250	0	0	631
21	Annual MWh Sales		2,270,721.284	784,751	1,466,635	125,788	1,340,847	1,172,103	168,745	0	0	19,336
22	On Pk Reqt	Mills / kWh	23.162	21.036	24.520	27.045	24.283	24.514	22.679	0.000	0.000	6.470
23	Off Pk Reqt	Mills / kWh	21.045	23.118	19.868	18.719	19.976	19.931	20.288	0.000	0.000	26.150
24	Total Reqt	Mills / kWh	44.207	44.154	44.388	45.764	44.259	44.446	42.966	0.000	0.000	32.619
	Equal Demand Classification											
25	Energy-Related Prod		21,788	7,464	14,196	1,260	12,936	11,384	1,552	0	0	128
26	Capacity-Related Summer Peak Prod		23,303	6,962	16,340	1,388	14,952	13,358	1,595	0	0	0
27	Capacity-Related Winter Peak Prod		8,366	3,289	4,982	545	4,437	3,981	456	0	0	95
28	Total Capacity-Related Prod		31,669	10,251	21,322	1,933	19,389	17,339	2,050	0	0	95
29	Total Production		53,457	17,716	35,518	3,193	32,326	28,723	3,603	0	0	223
30	Transmission **(Transco)**		18,447	6,248	12,110	1,142	10,968	9,814	1,154	0	0	89
31	Primary Dist Subs		3,072	1,128	1,914	169	1,745	1,537	207	0	0	29
32	Prim Dist Lines		3,450	1,121	2,300	170	2,130	1,874	256	0	0	29
33	Second Dist, Trans		3,887	1,961	1,903	209	1,693	1,693	0	0	0	23
34	Total Distribution **(Disco)**		10,409	4,210	6,116	549	5,568	5,105	463	0	0	82
35	Total Demand Rev Reqt		82,313	28,174	53,744	4,883	48,861	43,641	5,220	0	0	394
36	Annual Billing kW		3,581,533	0	3,581,533	0	3,581,533	3,238,674	342,859	0	0	0
37	Base Rev Reqt	$ / kW	$0.00	$0.00	$3.96	$0.00	$3.61	$3.52	$4.53	$0.00	$0.00	$0.00
38	Summer Rev Reqt	$ / kW	$0.00	$0.00	$4.56	$0.00	$4.17	$4.12	$4.65	$0.00	$0.00	$0.00
39	Winter Rev Reqt	$ / kW	$0.00	$0.00	$1.39	$0.00	$1.24	$1.23	$1.33	$0.00	$0.00	$0.00
40	Prod Rev Reqt	$ / kW	$0.00	$0.00	$9.92	$0.00	$9.03	$8.87	$10.51	$0.00	$0.00	$0.00
41	Tran Rev Reqt	$ / kW	$0.00	$0.00	$3.38	$0.00	$3.06	$3.03	$3.37	$0.00	$0.00	$0.00
42	Dist Rev Reqt	$ / kW	$0.00	$0.00	$1.71	$0.00	$1.55	$1.58	$1.35	$0.00	$0.00	$0.00
43	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$15.01	$0.00	$13.64	$13.47	$15.22	$0.00	$0.00	$0.00
44	Tot Dmd Rev Reqt	Mills / kWh	36.250	35.902	36.645	38.823	36.440	37.233	30.933	0.000	0.000	20.389
45	Summer Billing kW		1,257,547	0	1,257,547	0	1,257,547	1,129,313	128,234	0	0	0
46	Winter Billing kW		2,323,986	0	2,323,986	0	2,323,986	2,109,361	214,625	0	0	0
47	Tot Summer Reqt	$ / kW	$0.00	$0.00	$22.05	$0.00	$20.12	$19.95	$21.68	$0.00	$0.00	$0.00
48	Tot Winter Reqt	$ / kW	$0.00	$0.00	$11.20	$0.00	$10.14	$10.01	$11.37	$0.00	$0.00	$0.00
49	Energy + Production **(Genco)**		153,839	52,366	100,620	8,949	91,671	80,818	10,853	0	0	854

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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**	**Ltg**
1	**Proposed Ret On Rt Base**		**7.90%**	**8.26%**	**7.72%**	**8.57%**	**7.63%**	**8.05%**	**4.24%**	**0.00%**	**0.00%**	**4.33%**
2	**UnAdj Equalized Rev Reqt**		**199,597**	**75,923**	**121,524**	**12,283**	**109,241**	**96,743**	**12,499**	**0**	**0**	**2,150**
3	**Proposed Revenue**		**199,597**	**76,777**	**120,872**	**12,537**	**108,334**	**97,181**	**11,154**	**0**	**0**	**1,948**
4	**UnAdj Revenue Deficiency**		**0**	**(854)**	**653**	**(254)**	**907**	**(438)**	**1,345**	**0**	**0**	**202**
5	**UnAdj Deficiency / Proposed**		**0.00%**	**-1.11%**	**0.54%**	**-2.03%**	**0.84%**	**-0.45%**	**12.06%**	**0%**	**0%**	**10.35%**
6	**Prop Interrupt Rate Discounts**		**4,972**	**844**	**4,128**	**51**	**4,077**	**2,927**	**1,150**	**0**	**0**	**0**
7	**Prop Interrupt Capacity Costs**	**D10C**	**4,972**	**1,612**	**3,345**	**304**	**3,041**	**2,720**	**322**	**0**	**0**	**15**
8	**Revenue Shift**		**0**	**770**	**(784)**	**241**	**(1,025)**	**(204)**	**(821)**	**0**	**0**	**14**
9	**Adj Equal Rev (Rows 2+8)**		**199,597**	**76,693**	**120,740**	**12,524**	**108,216**	**96,539**	**11,677**	**0**	**0**	**2,164**
10	**Adj Rev Defic vs Prop Rev (Row 3)**		**0**	**(84)**	**(131)**	**(13)**	**(118)**	**(642)**	**523**	**0**	**0**	**216**
11	**Adj Deficiency / Adj Prop**		**0.00%**	**-0.11%**	**-0.11%**	**-0.10%**	**-0.11%**	**-0.66%**	**4.69%**	**0.00%**	**0.00%**	**11.09%**
	Prop Customer Component											
12	Min Sys & Service Drop		11,766	9,086	1,674	1,057	617	597	20	0	0	1,006
13	Energy Services		5,236	4,173	1,038	619	419	413	5	0	0	25
14	Total Customer **(Cusco)**		17,002	13,259	2,712	1,676	1,036	1,011	26	0	0	1,031
15	Ave Monthly Customers		91,774	77,450	12,459	8,812	3,648	3,614	33	0	0	1,865
16	Svc Drop Reqt	$ / Mo / Cust	$10.68	$9.78	$11.20	$9.99	$14.11	$13.77	$50.84	$0.00	$0.00	$44.95
17	Ener Svcs Reqt	$ / Mo / Cust	$4.75	$4.49	$6.94	$5.86	$9.56	$9.53	$12.96	$0.00	$0.00	$1.10
18	Total Reqt	$ / Mo / Cust	$15.44	$14.27	$18.14	$15.85	$23.67	$23.30	$63.80	$0.00	$0.00	$46.05
	Prop Energy Component											
19	On Peak Rev Reqt		52,594	16,514	35,955	3,404	32,551	28,737	3,814	0	0	125
20	Off Peak Rev Reqt		47,784	18,147	29,133	2,356	26,777	23,365	3,412	0	0	504
21	Total Ener Rev Reqt		100,378	34,661	65,088	5,760	59,328	52,102	7,227	0	0	629
22	Annual MWh Sales		2,270,721	784,751	1,466,635	125,788	1,340,847	1,172,103	168,745	0	0	19,336
23	On Pk Reqt	Mills / kWh	23.162	21.043	24.516	27.062	24.277	24.517	22.605	0.000	0.000	6.449
24	Off Pk Reqt	Mills / kWh	21.044	23.125	19.864	18.730	19.970	19.934	20.221	0.000	0.000	26.066
25	Total Reqt	Mills / kWh	44.205	44.168	44.379	45.792	44.247	44.451	42.826	0.000	0.000	32.515
	Prop Demand Component											
26	Energy-Related Prod		21,671	7,777	13,823	1,357	12,466	11,577	889	0	0	71
27	Capacity-Related Summer Peak Prod		23,288	7,053	16,235	1,422	14,814	13,429	1,385	0	0	0
28	Capacity-Related Winter Peak Prod		8,371	3,332	4,956	558	4,398	4,002	396	0	0	83
29	Total Capacity-Related Prod		31,659	10,384	21,192	1,980	19,212	17,431	1,781	0	0	83
30	Total Production		53,330	18,161	35,015	3,337	31,678	29,009	2,669	0	0	155
31	Transmission **(Transco)**		18,442	6,414	11,963	1,199	10,764	9,921	843	0	0	66
32	Primary Dist Subs		3,066	1,148	1,893	175	1,718	1,549	170	0	0	24
33	Prim Dist Lines		3,440	1,137	2,278	175	2,104	1,885	219	0	0	25
34	Second Dist, Trans		3,938	1,997	1,922	216	1,706	1,706	0	0	0	19
35	Total Distribution **(Disco)**		10,445	4,282	6,094	566	5,528	5,139	389	0	0	69
36	Total Demand Rev Reqt		82,217	28,857	53,071	5,101	47,970	44,068	3,902	0	0	289
37	Annual Billing kW		3,581,533	0	3,581,533	0	3,581,533	3,238,674	342,859	0	0	0
38	Base Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$3.48	$3.57	$2.59	$0.00	$0.00	$0.00
39	Summer Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$4.14	$4.15	$4.04	$0.00	$0.00	$0.00
40	Winter Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$1.23	$1.24	$1.15	$0.00	$0.00	$0.00
41	Prod Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$8.84	$8.96	$7.79	$0.00	$0.00	$0.00
42	Tran Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$3.01	$3.06	$2.46	$0.00	$0.00	$0.00
43	Dist Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$1.54	$1.59	$1.13	$0.00	$0.00	$0.00
44	Tot Dmd Rev Reqt	$ / kW	$0.00	$0.00	$0.00	$0.00	$13.39	$13.61	$11.38	$0.00	$0.00	$0.00
45	Tot Dmd Rev Reqt	Mills / kWh	36.207	36.772	36.186	40.554	35.776	37.598	23.121	0.000	0.000	14.941
46	Summer Billing kW		1,257,547	0	1,257,547	0	1,257,547	1,129,313	128,234	0	0	0
47	Winter Billing kW		2,323,986	0	2,323,986	0	2,323,986	2,109,361	214,625	0	0	0
48	Tot Summer Reqt	$ / kW	$0.00	$0.00	$21.81	$0.00	$19.81	$20.12	$16.98	$0.00	$0.00	$0.00
49	Tot Winter Reqt	$ / kW	$0.00	$0.00	$11.03	$0.00	$9.92	$10.12	$8.03	$0.00	$0.00	$0.00
50	Energy + Production **(Genco)**		153,708	52,822	100,103	9,097	91,006	81,110	9,896	0	0	783
51	Prop Rev - Pres Rev (Pg 2)		16,873	6,312	10,472	963	9,509	8,528	981	0	0	89
52	Difference / Present		9.23%	8.96%	9.49%	8.32%	9.62%	9.62%	9.65%	0.00%	0.00%	4.77%

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Original Plant in Service

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**Ltg**
1	Summer Peak	D10S	98,517	29,487	69,030	5,869	63,161	56,424	6,736	0	0	0
2	WInter Peak	D10W	35,379	13,929	21,047	2,304	18,742	16,817	1,925	0	0	403
3	Total Peak	D10C	133,896	43,416	90,077	8,174	81,903	73,241	8,662	0	0	403
4	Base Load	E8760	281,170	97,227	182,179	16,127	166,051	145,764	20,287	0	0	1,764
5	Nuclear Fuel	E8760	122,013	42,191	79,056	6,998	72,057	63,254	8,804	0	0	765
6	Total	32.26%	537,079	182,835	351,311	31,299	320,012	282,259	37,753	0	0	2,932
	Transmission											
7	Gen Step Up Base	E8760	2,969	1,027	1,924	170	1,753	1,539	214	0	0	19
8	Gen Step Up Peak	D10C	1,414	458	951	86	865	773	91	0	0	4
9	Total Gen Step Up		4,383	1,485	2,875	257	2,618	2,313	306	0	0	23
10	Bulk Transmission	D10T	131,815	44,715	86,464	8,163	78,301	70,066	8,235	0	0	635
11	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign	13	0	13	0	13	0	13	0	0	0
13	Total		136,211	46,201	89,352	8,420	80,933	72,379	8,554	0	0	658
	Distribution:											
	Substations											
14	Generat Step Up	STRATH	213	73	139	12	126	111	15	0	0	1
15	Bulk Transmission	D10T	108	37	71	7	64	57	7	0	0	1
16	Distrib Function	D60Sub	19,747	7,264	12,294	1,090	11,204	9,873	1,331	0	0	189
17	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
18	Total		20,068	7,373	12,504	1,109	11,395	10,042	1,353	0	0	191
	Overhead Lines											
19	Primary Capacity	D61PS	11,848	3,856	7,891	584	7,307	6,430	878	0	0	100
20	Primary Customer	C61PS	7,510	6,462	1,038	732	306	303	3	0	0	11
21	Total Primary		19,358	10,318	8,929	1,316	7,613	6,733	880	0	0	111
22	Second Capacity	D62SecL	4,713	2,233	2,449	266	2,183	2,183	0	0	0	31
23	Second Customer	C62Sec	4,757	4,095	656	464	192	192	0	0	0	7
24	Total Secondary		9,470	6,327	3,105	730	2,375	2,375	0	0	0	38
25	Street Lighting	DASL	1,067	0	0	0	0	0	0	0	0	1,067
26	Total		29,895	16,645	12,033	2,045	9,988	9,108	880	0	0	1,216
	Underground Lines											
27	Primary Capacity	D61PS	4,831	1,572	3,218	238	2,979	2,622	358	0	0	41
28	Primary Customer	C61PS	23,616	20,320	3,263	2,301	962	953	9	0	0	34
29	Total Primary		28,447	21,892	6,480	2,539	3,941	3,575	367	0	0	75
30	Second Capacity	D62SecL	11,627	5,508	6,042	656	5,386	5,386	0	0	0	77
31	Second Customer	C62Sec	12,842	11,054	1,770	1,252	518	518	0	0	0	18
32	Total Secondary		24,469	16,561	7,812	1,908	5,904	5,904	0	0	0	96
	Street Lighting	DASL	1,067	0	0	0	0	0	0	0	0	1,067
33	Total		53,983	38,453	14,292	4,447	9,845	9,479	367	0	0	1,237
	Line Transformers											
34	Primary	D61PS	711	231	474	35	438	386	53	0	0	6
35	Second Capacity	D62SecL	6,803	3,223	3,535	384	3,151	3,151	0	0	0	45
36	Second Customer	C62Sec	5,699	4,905	786	555	230	230	0	0	0	8
37	Total		13,213	8,359	4,794	974	3,820	3,767	53	0	0	59
	Services											
38	Second Capacity	D62NLL	3,719	3,012	707	106	602	602	0	0	0	0
39	Second Customer	C62NL	9,880	9,356	524	371	154	154	0	0	0	0
40	Total		13,599	12,367	1,232	476	756	756	0	0	0	0
41	Meters	C12WM	6,008	3,722	2,184	837	1,347	1,234	113	0	0	101
42	Street Lighting	Dir Assign	1,921	0	0	0	0	0	0	0	0	1,921
43	**Total Distribution**		138,687	86,921	47,040	9,889	37,151	34,385	2,766	0	0	4,726
44	**General Plant**	PTD	29,097	11,322	17,477	1,778	15,699	13,941	1,759	0	0	298
45	**Electric Common**	PTD	29,899	11,634	17,958	1,827	16,132	14,325	1,807	0	0	306
46	Prelim Elec Plant		870,972	338,913	523,139	53,213	469,926	417,288	52,638	0	0	8,920
47	TBT Investment	NEPIS	0	0	0	0	0	0	0	0	0	0
48	**Elec Plant in Serv**		870,972	338,913	523,139	53,213	469,926	417,288	52,638	0	0	8,920

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	Accum Deprec; Net Plant		1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Production	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**Ltg**
1	Peaking Plant	D10C	58,423	18,944	39,303	3,567	35,737	31,957	3,779	0	0	176
2	Decom Int Peaking	D10C	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	108,511	37,523	70,308	6,224	64,084	56,254	7,829	0	0	681
5	Base Load	E8760	122,565	42,383	79,414	7,030	72,384	63,540	8,844	0	0	769
6	Total		289,499	98,849	189,025	16,820	172,204	151,752	20,452	0	0	1,625
	Transmission											
7	Gen Step Up Base	E8760	1,281	443	830	73	757	664	92	0	0	8
8	Gen Step Up Peak	D10C	610	198	410	37	373	334	39	0	0	2
9	Total Gen Step Up		1,891	641	1,240	111	1,130	998	132	0	0	10
10	Bulk Transmission	D10T	36,892	12,515	24,199	2,285	21,915	19,610	2,305	0	0	178
11	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign	4	0	4	0	4	0	4	0	0	0
13	Total		38,787	13,156	25,444	2,395	23,048	20,608	2,441	0	0	188
	Distribution											
14	Generat Step Up	STRATH	109	37	71	6	65	57	8	0	0	1
15	Bulk Transmission	D10T	44	15	29	3	26	23	3	0	0	0
16	Distrib Function	D60Sub	9,032	3,322	5,623	498	5,125	4,516	609	0	0	87
17	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
18	Total Substations		9,185	3,375	5,723	507	5,216	4,596	619	0	0	87
19	Overhead Lines	POL	12,465	6,940	5,017	853	4,165	3,798	367	0	0	507
20	Underground	PUL	22,523	16,044	5,963	1,855	4,108	3,955	153	0	0	516
21	Line Transformers	P68	6,945	4,394	2,520	512	2,008	1,980	28	0	0	31
22	Services	P69	7,148	6,501	647	250	397	397	0	0	0	0
23	Meters	C12WM	3,158	1,957	1,148	440	708	649	59	0	0	53
24	Street Lighting	P73	1,523	0	0	0	0	0	0	0	0	1,523
25	Total		62,947	39,210	21,019	4,418	16,601	15,374	1,227	0	0	2,718
26	**General Plant**	PTD	11,053	4,301	6,639	675	5,964	5,296	668	0	0	113
27	**Electric Common**	PTD	17,303	6,733	10,393	1,057	9,336	8,290	1,046	0	0	177
28	**Total Accum Depr**		419,589	162,248	252,519	25,367	227,153	201,319	25,833	0	0	4,822
29	**Net Elec Plant**		451,383	176,665	270,619	27,846	242,773	215,969	26,805	0	0	4,099
30	**Net Plant w/ TBT**		451,383	176,665	270,619	27,846	242,773	215,969	26,805	0	0	4,099
	Subtractions: Accum Defer Inc Tax											
	Production											
31	Peaking Plant	D10C	16,036	5,200	10,788	979	9,809	8,772	1,037	0	0	48
32	Base Load	E8760	45,257	15,650	29,324	2,596	26,728	23,462	3,265	0	0	284
33	Nuclear Fuel	E8760	1,876	649	1,215	108	1,108	972	135	0	0	12
34	Total		63,169	21,498	41,327	3,682	37,645	33,206	4,438	0	0	344
	Transmission											
35	Gen Step Up Base	E8760	639	221	414	37	377	331	46	0	0	4
36	Gen Step Up Peak	D10C	304	99	205	19	186	166	20	0	0	1
37	Total Gen Step Up		943	320	619	55	563	498	66	0	0	5
38	Bulk Transmission	D10T	22,164	7,519	14,539	1,373	13,166	11,781	1,385	0	0	107
39	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
40	Direct Assign	Dir Assign	3	0	3	0	3	0	3	0	0	0
41	Total		23,110	7,838	15,160	1,428	13,732	12,279	1,453	0	0	112
	Distribution											
42	Generat Step Up	STRATH	42	14	27	2	25	22	3	0	0	0
43	Bulk Transmission	D10T	16	5	10	1	10	9	1	0	0	0
44	Distrib Function	D60Sub	2,613	961	1,627	144	1,483	1,306	176	0	0	25
45	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
46	Total Substations		2,671	981	1,665	148	1,517	1,337	180	0	0	25
47	Overhead Lines	POL	5,139	2,861	2,069	352	1,717	1,566	151	0	0	209
48	Underground	PUL	8,478	6,039	2,245	698	1,546	1,489	58	0	0	194
49	Line Transformers	P68	1,943	1,229	705	143	562	554	8	0	0	9
50	Services	P69	2,181	1,983	198	76	121	121	0	0	0	0
51	Meters	C12WM	870	539	316	121	195	179	16	0	0	15
52	Street Lighting	P73	(26)	0	0	0	0	0	0	0	0	(26)
53	Total		21,256	13,633	7,197	1,539	5,658	5,245	413	0	0	426
54	**General Plant**	PTD	3,848	1,497	2,311	235	2,076	1,844	233	0	0	39
55	**Electric Common**	PTD	2,264	881	1,360	138	1,222	1,085	137	0	0	23
56	**Total Deferred Tax**		113,647	45,348	67,355	7,022	60,333	53,659	6,674	0	0	944
57	Net Operating Loss (NOL) Carry Forward	NEPIS	(19,784)	(7,743)	(11,861)	(1,220)	(10,641)	(9,466)	(1,175)	0	0	(180)
58	Non-Plant Related	LABOR	(1,079)	(417)	(648)	(68)	(580)	(514)	(66)	0	0	(14)
59	**Accum Def W/ Adj**		92,784	37,188	54,845	5,733	49,112	43,678	5,434	0	0	750

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	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**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**Ltg**
1	Peaking Plant	D10C	193	63	130	12	118	106	12	0	0	1
2	Base Load	E8760	750	259	486	43	443	389	54	0	0	5
3	Nuclear Fuel	E8760	219	76	142	13	129	114	16	0	0	1
4	Total		1,162	398	758	67	690	608	82	0	0	7
	Transmission											
5	Gen Step Up Base	E8760	0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10C	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	D10T	723	245	474	45	429	384	45	0	0	3
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		723	245	474	45	429	384	45	0	0	3
	Distribution											
12	Generat Step Up	STRATH	0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub	6	2	4	0	3	3	0	0	0	0
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
16	Total Substations		6	2	4	0	3	3	0	0	0	0
17	Overhead Lines	POL	3	2	1	0	1	1	0	0	0	0
18	Underground	PUL	4	3	1	0	1	1	0	0	0	0
19	Line Transformers	P68	0	0	0	0	0	0	0	0	0	0
20	Services	P69	0	0	0	0	0	0	0	0	0	0
21	Meters	C12WM	0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73	0	0	0	0	0	0	0	0	0	0
23	Total		13	7	6	1	5	5	1	0	0	0
24	**General Plant**	PTD	93	36	56	6	50	45	6	0	0	1
25	**Electric Common**	PTD	46	18	28	3	25	22	3	0	0	0
26	**Total CWIP**		2,037	704	1,321	121	1,200	1,063	136	0	0	12
27	Fuel Inventory	E8760	5,899	2,040	3,822	338	3,484	3,058	426	0	0	37
	Materials & Supplies											
28	Production	P10	6,473	2,204	4,234	377	3,857	3,402	455	0	0	35
29	Trans & Distr	TD	1,140	552	566	76	490	443	47	0	0	22
30	Total		7,613	2,756	4,800	453	4,347	3,845	502	0	0	58
	Prepayments											
31	Miscellaneous	NEPIS	6,235	2,440	3,738	385	3,353	2,983	370	0	0	57
32	Total		6,235	2,440	3,738	385	3,353	2,983	370	0	0	57
33	Non-Plant Assets & Liab	LABOR	(1,809)	(698)	(1,087)	(115)	(972)	(862)	(110)	0	0	(24)
34	Working Cash	PT0	(926)	(369)	(546)	(58)	(489)	(436)	(53)	0	0	(10)
35	**Total Additions**		19,049	6,872	12,048	1,126	10,923	9,651	1,271	0	0	129
36	**Total Rate Base**		377,648	146,349	227,822	23,238	204,584	181,942	22,642	0	0	3,477
37	**Common Rate Base (@ 52.56%)**		198,491.8	76,921	119,743	12,214	107,529	95,629	11,901	0	0	1,828

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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**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**Ltg**
1	Present Rate Revenue	R01; (calc)	182,724	70,465	110,400	11,575	98,825	88,653	10,172	0	0	1,860
2	Proposed Rate Revenue	PROREV; (ca	199,597	76,777	120,872	12,537	108,334	97,181	11,154	0	0	1,948
3	Equal Rate Revenue		199,597	75,923	121,524	12,283	109,241	96,743	12,499	0	0	2,150
	Other Retail Revenue											
4	Interdepartmental	R01; R02	0	0	0	0	0	0	0	0	0	0
5	Gross Earnings Tax	R01; R02	0	0	0	0	0	0	0	0	0	0
6	CIP Adjustment to Program Costs	D99E1	0	0	0	0	0	0	0	0	0	0
7	**Tot Other Retail Rev**		0	0	0	0	0	0	0	0	0	0
	Other Operating Revenue											
8	Interchg Prod Capacity	P10	11,897	4,050	7,782	693	7,089	6,252	836	0	0	65
9	Interchg Prod Energy	E8760	13,089	4,526	8,481	751	7,730	6,786	944	0	0	82
10	Interchg Tr Bulk Supply	D10T	2,629	892	1,725	163	1,562	1,397	164	0	0	13
11	Dist Int Sales; Oth Serv	E8760	0	0	0	0	0	0	0	0	0	0
12	Dist Overhd Line Rent	POL	268	149	108	18	90	82	8	0	0	11
13	Connection Charges	C11	274	231	37	26	11	11	0	0	0	6
14	Sales For Resale	E8760	9,115	3,152	5,906	523	5,383	4,725	658	0	0	57
15	Joint Op Agree-Other PSCo Rev	D10T	(370)	(126)	(243)	(23)	(220)	(197)	(23)	0	0	(2)
16	Misc Ancillary Trans Rev	D10T	8,127	2,757	5,331	503	4,828	4,320	508	0	0	39
17	MISO	D10T	100	34	66	6	59	53	6	0	0	0
18	Other	D10T	95	32	62	6	56	50	6	0	0	0
19	Late Pay Chg - Pres	R16C; R02	278.0000	215	63	18	45	40	5	0	0	0
20	**Tot Other Op - Pres**		45,502	15,913	29,317	2,685	26,632	23,520	3,112	0	0	272
21	Incr Misc Serv - Prop	R01,	0	0	0	0	0	0	0	0	0	0
22	Incr Inter-Dept'l - Prop	R01; R02	0	0	0	0	0	0	0	0	0	0
23	Incr Late Pay - Prop	(R16C); R02	26	20	6	2	4	4	0	0	0	0
24	**Tot Other Op - Prop**		45,528	15,933	29,323	2,687	26,636	23,524	3,113	0	0	272
25	**Tot Oper Rev - Pres**		228,226	86,378	139,717	14,260	125,457	112,173	13,285	0	0	2,131
26	**Tot Oper Rev - Prop**		245,125	92,710	150,195	15,224	134,971	120,704	14,266	0	0	2,220
	Tot Oper Rev - Eql		245,125	91,856	150,848	14,970	135,878	120,266	15,611	0	0	2,422

Operating & Maint (Pg 1 of 2)

			MN	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Tr Transf	Trans	Ltg
	Production Expen											
27	**Fuel**	E8760	38,194	13,207	24,747	2,191	22,556	19,801	2,756	0	0	240
	Purchased Power											
28	Purchases: Cap Peak	D10C	7,397	2,399	4,976	452	4,525	4,046	479	0	0	22
29	Purchases: Cap Base	D10C	2,752	892	1,851	168	1,683	1,505	178	0	0	8
30	Purchases: Demand		10,149	3,291	6,828	620	6,208	5,552	657	0	0	31
31	Purchases: Other Energy	E8760	43,438	15,021	28,145	2,492	25,653	22,519	3,134	0	0	273
32	Tot Non-Assoc Purch		53,587	18,312	34,972	3,111	31,861	28,071	3,791	0	0	303
33	Interchg Agr Capacity	P10WoN	2,897	982	1,900	170	1,731	1,529	202	0	0	15
34	Interchg Agr Energy	E8760	1,339	463	868	77	791	694	97	0	0	8
35	Tot Wis Interchg Purch		4,236	1,445	2,768	246	2,521	2,223	299	0	0	24
36	**Tot Purchased Power**		57,823	19,756	37,740	3,357	34,383	30,293	4,089	0	0	327
	Other Production											
37	Capacity Related	D10C	8,271	2,682	5,564	505	5,059	4,524	535	0	0	25
38	Energy Related	E8760	24,904	8,612	16,136	1,428	14,708	12,911	1,797	0	0	156
39	Total Other Produc		33,175	11,294	21,700	1,933	19,767	17,435	2,332	0	0	181
40	**Total Production**		129,192	44,257	84,188	7,482	76,706	67,529	9,177	0	0	747
41	**Transmission Exp**	D10T	14,031	4,760	9,204	869	8,335	7,458	877	0	0	68

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			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Distribution Expen	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**Ltg**
1	Supervision & Eng'rg	ZDTS	770	404	319	56	263	240	24	0	0	47
2	Load Dispatching	D10T	240	81	157	15	143	128	15	0	0	1
3	Substations	P61	522	192	325	29	296	261	35	0	0	5
4	Overhead Lines	POL	2,399	1,336	966	164	802	731	71	0	0	98
5	Underground Lines	PUL	1,286	916	340	106	235	226	9	0	0	29
6	Line Transformers	P68	2	1	1	0	1	1	0	0	0	0
7	Meters	C12WM	242	150	88	34	54	50	5	0	0	4
8	Customer Install'n	OXDTS	177	95	66	12	54	49	5	0	0	16
9	Street Lighting	Dir Assign	328	0	0	0	0	0	0	0	0	328
10	Miscellaneous	OXDTS	571	305	214	40	175	159	15	0	0	52
11	Rents (Pole Attachmts)	POL	226	126	91	15	76	69	7	0	0	9
12	**Total Distribution**		6,763	3,606	2,568	471	2,098	1,913	184	0	0	589
13	**Customer Accounting**	C11WA	4,286	3,406	863	512	351	347	4	0	0	16
14	**Sales, Econ Dvlp & Other**	D57E43	173	58	115	10	104	93	12	0	0	1
	Admin & General											
15	Salaries	LABOR	3,332	1,286	2,002	211	1,791	1,588	202	0	0	44
16	Office Supplies	OXTS	3,004	1,098	1,878	182	1,695	1,497	198	0	0	28
17	Admin Transfer Credit	OXTS	(1,507)	(551)	(942)	(92)	(850)	(751)	(99)	0	0	(14)
18	Outside Services	LABOR	917	354	551	58	493	437	56	0	0	12
19	Property Insurance	NEPIS	726	284	435	45	390	347	43	0	0	7
20	Pensions & Benefits	LABOR	5,843	2,255	3,510	370	3,140	2,785	355	0	0	77
21	Injuries & Claims	LABOR	1,071	413	643	68	576	511	65	0	0	14
22	Regulatory Exp	R01; R02	105	40	63	7	57	51	6	0	0	1
23	General Advertising	OXTS	86	31	54	5	49	43	6	0	0	1
24	Contributions	OXTS	0	0	0	0	0	0	0	0	0	0
25	Misc General Exp	OXTS	(99)	(36)	(62)	(6)	(56)	(49)	(7)	0	0	(1)
26	Rents	OXTS	1,316	481	823	80	743	656	87	0	0	12
27	Maint of General Plant	OXTS	28	10	18	2	16	14	2	0	0	0
28	Total		14,822	5,667	8,973	930	8,043	7,129	913	0	0	182
	Cust Service & Info											
29	Cust Assist Exp - Non-CIP	C11P10	320	189	126	25	102	90	11	0	0	4
30	CIP Total	D99E1	0	0	0	0	0	0	0	0	0	0
31	Instructional Advertising	C11P10	137	81	54	11	44	39	5	0	0	2
32	Total		457	271	180	35	145	129	16	0	0	6
33	Amortizations	LABOR	373	144	224	24	200	178	23	0	0	5
34	**Total O&M Expense**		170,097	62,169	106,315	10,332	95,982	84,776	11,206	0	0	1,614

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Exhibit___(MAP-1)
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Northern States Power Company
Electric Utility - State of North Dakota
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Proposed Class Cost of Service Study Detail

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
	Book Depreciation											
	Production	**Alloc**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**Ltg**
1	Peaking Plant	D10C	3,901	1,265	2,624	238	2,386	2,134	252	0	0	12
2	Base Load	E8760	8,563	2,961	5,548	491	5,057	4,439	618	0	0	54
3	Total		12,464	4,226	8,173	729	7,443	6,573	870	0	0	65
	Transmission											
4	Gen Step Up Base	E8760	60	21	39	3	36	31	4	0	0	0
5	Gen Step Up Peak	D10C	29	9	19	2	18	16	2	0	0	0
6	Total Gen Step Up		89	30	58	5	53	47	6	0	0	0
7	Bulk Transmission	D10T	2,271	770	1,490	141	1,349	1,207	142	0	0	11
8	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
9	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
10	Total		2,360	801	1,548	146	1,402	1,254	148	0	0	11
	Distribution											
11	Generat Step Up	STRATH	8	3	5	0	5	4	1	0	0	0
12	Bulk Transmission	D10T	4	1	3	0	2	2	0	0	0	0
13	Distrib Function	D60Sub	608	224	379	34	345	304	41	0	0	6
14	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
15	Total Substations		620	228	386	34	352	310	42	0	0	6
16	Overhead Lines	POL	878	489	353	60	293	267	26	0	0	36
17	Underground	PUL	1,587	1,130	420	131	289	279	11	0	0	36
18	Line Transformers	P68	499	316	181	37	144	142	2	0	0	2
19	Services	P69	515	468	47	18	29	29	0	0	0	0
20	Meters	C12WM	227	141	83	32	51	47	4	0	0	4
21	Street Lighting	P73	81	0	0	0	0	0	0	0	0	81
22	Total		4,407	2,772	1,470	312	1,159	1,074	85	0	0	165
23	**General Plant**	PTD	1,118	435	672	68	603	536	68	0	0	11
24	**Electric Common**	PTD	2,214	862	1,330	135	1,195	1,061	134	0	0	23
25	**Total Book Deprec**		22,563	9,095	13,192	1,390	11,802	10,498	1,304	0	0	276
	Real Estate & Property Tax											
	Production											
26	Peaking Plant	D10C	1,315	426	885	80	804	719	85	0	0	4
27	Base Load	E8760	2,760	954	1,788	158	1,630	1,431	199	0	0	17
28	Total		4,075	1,381	2,673	239	2,434	2,150	284	0	0	21
	Transmission											
29	Gen Step Up Base	E8760	48.2385	17	31	3	28	25	3	0	0	0
30	Gen Step Up Peak	D10C	22.9717	7	15	1	14	13	1	0	0	0
31	Total Gen Step Up		71.2102	24	47	4	43	38	5	0	0	0
32	Bulk Transmission	D10T	2,141.5786	726	1,405	133	1,272	1,138	134	0	0	10
33	Distrib Function	D60Sub	0.0000	0	0	0	0	0	0	0	0	0
34	Direct Assign	Dir Assign	0.2112	0	0	0	0	0	0	0	0	0
35	Total		2,213.000	751	1,452	137	1,315	1,176	139	0	0	11
	Distribution											
36	Generat Step Up	STRATH	3	1	2	0	2	1	0	0	0	0
37	Bulk Transmission	D10T	1	0	1	0	1	1	0	0	0	0
38	Distrib Function	D60Sub	235	87	146	13	133	118	16	0	0	2
39	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
40	Total Substations		239	88	149	13	136	120	16	0	0	2
41	Overhead Lines	POL	356	198	143	24	119	108	10	0	0	14
42	Underground	PUL	643	458	170	53	117	113	4	0	0	15
43	Line Transformers	P68	157	100	57	12	45	45	1	0	0	1
44	Services	P69	162	147	15	6	9	9	0	0	0	0
45	Meters	C12WM	72	44	26	10	16	15	1	0	0	1
46	Street Lighting	P73	23	0	0	0	0	0	0	0	0	23
47	Total		1,652	1,035	560	118	443	410	33	0	0	56
48	**General Plant**	PTD	0	0	0	0	0	0	0	0	0	0
49	**Electric Common**	PTD	0	0	0	0	0	0	0	0	0	0
50	**Tot Rl Est & Pr Tax**		7,940	3,167	4,685	493	4,192	3,736	456	0	0	88
51	Gross Earnings Tax	R01; R02	0	0	0	0	0	0	0	0	0	0
52	Payroll Taxes	LABOR	1,931	745	1,160	122	1,038	921	117	0	0	26
53	**Tot Non-Inc Taxes**		9,871	3,912	5,845	615	5,230	4,656	573	0	0	114

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	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**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**Ltg**
1	Peaking Plant	D10C	1,653	536	1,112	101	1,011	904	107	0	0	5
2	Nuclear Fuel	E8760	(637)	(220)	(413)	(37)	(376)	(330)	(46)	0	0	(4)
3	Base Load	E8760	5,570	1,926	3,609	320	3,290	2,888	402	0	0	35
4	Total		6,586	2,242	4,308	384	3,924	3,462	463	0	0	36
	Transmission											
5	Gen Step Up Base	E8760	1	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10C	0	0	0	0	0	0	0	0	0	0
7	Total Gen Step Up		1	0	1	0	1	1	0	0	0	0
8	Bulk Transmission	D10T	2,848	966	1,868	176	1,692	1,514	178	0	0	14
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		2,849	967	1,869	176	1,693	1,515	178	0	0	14
	Distribution											
12	Generat Step Up	STRATH	(3)	(1)	(2)	(0)	(2)	(2)	(0)	0	0	(0)
13	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub	89	33	55	5	50	44	6	0	0	1
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
16	Total Substations		86	32	53	5	49	43	6	0	0	1
17	Overhead Lines	POL	35	19	14	2	12	11	1	0	0	1
18	Underground	PUL	(128)	(91)	(34)	(11)	(23)	(22)	(1)	0	0	(3)
19	Line Transformers	P68	(129)	(82)	(47)	(10)	(37)	(37)	(1)	0	0	(1)
20	Services	P69	(134)	(122)	(12)	(5)	(7)	(7)	0	0	0	0
21	Meters	C12WM	(11)	(7)	(4)	(2)	(2)	(2)	(0)	0	0	(0)
22	Street Lighting	P73	(8)	0	0	0	0	0	0	0	0	(8)
23	Total		(289)	(250)	(29)	(19)	(10)	(15)	5	0	0	(9)
24	**General Plant**	PTD	145	56	87	9	78	69	9	0	0	1
25	**Electric Common**	PTD	(309)	(120)	(186)	(19)	(167)	(148)	(19)	0	0	(3)
26	**Net Operating Loss (NOL) Carry Forward**	NEPIS	2,982	1,167	1,788	184	1,604	1,427	177	0	0	27
27	**Non - Plant Related**	LABOR	887	342	533	56	477	423	54	0	0	12
28	**Tot Prov For Defer**		12,851	4,404	8,370	771	7,599	6,732	867	0	0	77
	Inv Tax Credit; Total Oper Exp											
	Production											
29	Peaking Plant	D10C	(19)	(6)	(13)	(1)	(12)	(10)	(1)	0	0	(0)
30	Base Load	E8760	(38)	(13)	(25)	(2)	(22)	(20)	(3)	0	0	(0)
31	Total		(57)	(19)	(37)	(3)	(34)	(30)	(4)	0	0	(0)
	Transmission											
32	Bulk Transmission	D10T	(33)	(11)	(22)	(2)	(20)	(18)	(2)	0	0	(0)
33	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
34	Total		(33)	(11)	(22)	(2)	(20)	(18)	(2)	0	0	(0)
	Distribution											
35	Generat Step Up	STRATH	0	0	0	0	0	0	0	0	0	0
36	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0	0
37	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
38	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
39	Total Substations		0	0	0	0	0	0	0	0	0	0
40	Overhead Lines	POL	0	0	0	0	0	0	0	0	0	0
41	Underground	PUL	0	0	0	0	0	0	0	0	0	0
42	Line Transformers	P68	0	0	0	0	0	0	0	0	0	0
43	Services	P69	0	0	0	0	0	0	0	0	0	0
44	Meters	C12WM	0	0	0	0	0	0	0	0	0	0
45	Street Lighting	P73	0	0	0	0	0	0	0	0	0	0
46	Total		0	0	0	0	0	0	0	0	0	0
47	**General Plant**	PTD	0	0	0	0	0	0	0	0	0	0
48	**Electric Common**	PTD	(1)	(0)	(1)	(0)	(1)	(0)	(0)	0	0	(0)
49	**Net Inv Tax Credit**		(91)	(31)	(60)	(5)	(54)	(48)	(6)	0	0	(0)
50	**Total Operating Exp**		**215,291**	**79,548**	**133,662**	**13,104**	**120,559**	**106,613**	**13,945**	**0**	**0**	**2,080**
51A	**Pres Op Inc Before Inc Tax**		**12,935**	**6,829**	**6,054**	**1,156**	**4,899**	**5,559**	**(661)**	**0**	**0**	**51**
51B	**Prop Op Inc Before Inc Tax**		**29,833**	**13,161**	**16,532**	**2,120**	**14,412**	**14,091**	**321**	**0**	**0**	**140**

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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**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**Ltg**
1	Peaking Plant	D10C	8,946	2,901	6,018	546	5,472	4,893	579	0	0	27
2	Nuclear Fuel	E8760	5,361	1,854	3,474	307	3,166	2,779	387	0	0	34
3	Base Load	E8760	26,620	9,205	17,248	1,527	15,721	13,801	1,921	0	0	167
4	Total		40,927	13,960	26,740	2,380	24,359	21,473	2,886	0	0	228
	Transmission											
5	Gen Step Up Base	E8760	62	22	40	4	37	32	4	0	0	0
6	Gen Step Up Peak	D10C	30	10	20	2	18	16	2	0	0	0
7	Total Gen Step Up		92	31	60	5	55	49	6	0	0	0
8	Bulk Transmission	D10T	10,250	3,477	6,724	635	6,089	5,448	640	0	0	49
9	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	1	0	1	0	1	0	1	0	0	0
11	Total		10,343	3,508	6,785	640	6,145	5,497	648	0	0	50
	Distribution											
12	Generat Step Up	STRATH	0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10T	2	1	1	0	1	1	0	0	0	0
14	Distrib Function	D60Sub	842	310	524	46	478	421	57	0	0	8
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
16	Total Substations		844	310	526	47	479	422	57	0	0	8
17	Overhead Lines	POL	1,011	563	407	69	338	308	30	0	0	41
18	Underground	PUL	1,247	888	330	103	227	219	8	0	0	29
19	Line Transformers	P68	185	117	67	14	53	53	1	0	0	1
20	Services	P69	228	207	21	8	13	13	0	0	0	0
21	Meters	C12WM	184	114	67	26	41	38	3	0	0	3
22	Street Lighting	P73	59	0	0	0	0	0	0	0	0	59
23	Total		3,758	2,200	1,417	266	1,152	1,052	99	0	0	141
24	**General Plant**	PTD	2,011	783	1,208	123	1,085	963	122	0	0	21
25	**Electric Common**	PTD	1,420	553	853	87	766	680	86	0	0	15
26	Net Operating Loss (NOL) Carry Forward	NEPIS	10,641	4,165	6,380	656	5,723	5,091	632	0	0	97
27	**Total Tax Deprec**		69,100	25,168	43,382	4,152	39,230	34,757	4,473	0	0	550
28	Interest Expense		8,799	3,410	5,308	541	4,767	4,239	528	0	0	81
29	Other Tax Timing Differ		2,176	738	1,427	135	1,293	1,157	136	0	0	10
30	Total Tax Deductions		80,075	29,316	50,118	4,829	45,289	40,153	5,136	0	0	641
	Inc Tax Additions											
31	Book Depreciation		22,563	9,095	13,192	1,390	11,802	10,498	1,304	0	0	276
32	Deferred Inc Tax & ITC		12,760	4,373	8,310	766	7,545	6,684	861	0	0	77
33	Nuclear Fuel Book Burn	E8760	7,249	2,507	4,697	416	4,281	3,758	523	0	0	45
34	Tax Capitalized Leases	PTD	4,664	1,815	2,801	285	2,516	2,235	282	0	0	48
35	Meals & Entertainment	LABOR	(47)	(18)	(28)	(3)	(25)	(22)	(3)	0	0	(1)
36	Avoided Tax Interest	RTBASE	3,051	1,182	1,841	188	1,653	1,470	183	0	0	28
37	Total Tax Additions		50,240	18,953	30,813	3,042	27,772	24,621	3,150	0	0	474
38	**Total Inc Tax Adjustments**		(29,835)	(10,362)	(19,305)	(1,787)	(17,518)	(15,532)	(1,986)	0	0	(168)
39A	**Pres Taxable Net Income**		(16,900)	(3,533)	(13,250)	(631)	(12,619)	(9,973)	(2,646)	0	0	(117)
39B	**Prop Taxable Net Income**		(2)	2,799	(2,772)	333	(3,106)	(1,441)	(1,664)	0	0	(28)
40A	Pres Fed & State Inc Tax		(6,481)	(1,355)	(5,081)	(242)	(4,839)	(3,824)	(1,015)	0	0	(45)
40B	Prop Fed & State Inc Tax		(1)	1,073	(1,063)	128	(1,191)	(553)	(638)	0	0	(11)
41A	Pres Preliminary Return	(total); BASE	19,416	8,184	11,136	1,398	9,738	9,383	354	0	0	96
41B	Prop Preliminary Return	(total); BASE	29,834	12,088	17,596	1,992	15,603	14,643	960	0	0	150
42	Total AFUDC		0	0	0	0	0	0	0	0	0	0
43A	**Present Total Return**		19,416	8,184	11,136	1,398	9,738	9,383	354	0	0	96
43B	**Proposed Total Return**		29,834	12,088	17,596	1,992	15,603	14,643	960	0	0	150
43C	**Equal Total Return**		29,834	11,562	17,998	1,836	16,162	14,373	1,789	0	0	275
44A	**Pres % Return on Rate Base**		5.14%	5.59%	4.89%	6.02%	4.76%	5.16%	1.56%	0.00%	0.00%	2.75%
44B	**Prop % Return on Rate Base**		7.90%	8.26%	7.72%	8.57%	7.63%	8.05%	4.24%	0.00%	0.00%	4.33%
44C	**Equal % Return on Rate Base**		7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	0.00%	0.00%	7.90%
45A	**Present Common Return**		10,616	4,774	5,827	857	4,971	5,144	(173)	0	0	15
45B	**Proposed Common Return**		21,035	8,678	12,287	1,451	10,836	10,404	432	0	0	69
46A	**Pres % Ret on Common Rt Base**		5.35%	6.21%	4.87%	7.01%	4.62%	5.38%	-1.46%	0.00%	0.00%	0.81%
46B	**Prop % Ret on Common Rt Base**		10.60%	11.28%	10.26%	11.88%	10.08%	10.88%	3.63%	0.00%	0.00%	3.80%

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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**	**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**Ltg**
1	Peaking Plant	D10C	0	0	0	0	0	0	0	0	0	0
2	Nuclear Fuel	E8760	0	0	0	0	0	0	0	0	0	0
3	Base Load	E8760	0	0	0	0	0	0	0	0	0	0
4	Total		0	0	0	0	0	0	0	0	0	0
	Transmission											
5	Gen Step Up Base	E8760	0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10C	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	D10T	0	0	0	0	0	0	0	0	0	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		0	0	0	0	0	0	0	0	0	0
	Distribution											
12	Generat Step Up	STRATH	0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0
16	Total Substations		0	0	0	0	0	0	0	0	0	0
17	Overhead Lines	POL	0	0	0	0	0	0	0	0	0	0
18	Underground	PUL	0	0	0	0	0	0	0	0	0	0
19	Line Transformers	P68	0	0	0	0	0	0	0	0	0	0
20	Services	P69	0	0	0	0	0	0	0	0	0	0
21	Meters	C12WM	0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73	0	0	0	0	0	0	0	0	0	0
23	Total		0	0	0	0	0	0	0	0	0	0
24	**General Plant**	PTD	0	0	0	0	0	0	0	0	0	0
25	**Electric Common**	PTD	0	0	0	0	0	0	0	0	0	0
26	**Total AFUDC**		0	0	0	0	0	0	0	0	0	0
	Labor Allocator											
	Production											
27	Other Prod - Cap	D10C	74,009	23,998	49,789	4,518	45,271	40,483	4,788	0	0	223
28	Other Prod - Ene	E8760	155,413	53,741	100,697	8,914	91,783	80,569	11,214	0	0	975
29	Total		229,422	77,739	150,485	13,432	137,053	121,052	16,001	0	0	1,198
	Transmission											
30	Stepup Subtrans	P5161A	483	164	317	28	288	255	34	0	0	3
31	Bulk Power Subs	D10T	14,532	4,930	9,532	900	8,632	7,724	908	0	0	70
32	Total		15,015	5,093	9,849	928	8,921	7,979	942	0	0	73
	Distribution											
33	Superv & Eng	ZDTS	7,264	3,813	3,011	527	2,484	2,261	223	0	0	440
34	Load Dispatch	D10T	4,937	1,675	3,238	306	2,933	2,624	308	0	0	24
35	Substation	P61	4,117	1,513	2,565	227	2,338	2,060	278	0	0	39
36	Overhead Lines	POL	6,833	3,805	2,750	468	2,283	2,082	201	0	0	278
37	Underground Lines	PUL	7,664	5,459	2,029	631	1,398	1,346	52	0	0	176
38	Line Transformer	P68	1,326	839	481	98	383	378	5	0	0	6
39	Meter	C12WM	2,465	1,527	896	343	553	506	46	0	0	42
40	Cust Installation	ZDTS	2,602	1,366	1,078	189	890	810	80	0	0	158
41	Street Lighting	P73	982	0	0	0	0	0	0	0	0	982
42	Miscellaneous	OXDTS	5,661	3,024	2,125	392	1,733	1,581	152	0	0	512
43	Total		43,851	23,021	18,174	3,181	14,993	13,647	1,346	0	0	2,656
44	**Cust Accounting**	C11WA	12,343	9,810	2,486	1,474	1,012	1,000	13	0	0	47
45	**Sales Expense**	C11P10	92	54	36	7	29	26	3	0	0	1
46	**Admin & General**	LABOR	117,017	45,170	70,301	7,411	62,890	55,785	7,105	0	0	1,546
47	**Service & Inform**	C11P10	1,766	1,046	697	136	561	499	62	0	0	23
48	**Labor**		419,506	161,933	252,029	26,570	225,460	199,988	25,472	0	0	5,543

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			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**	**Ltg**
1	50% Cus, 50% Prod Plt	C11P10	100.000%	59.217%	39.494%	7.715%	31.779%	28.246%	3.533%	0.000%	0.000%	1.289%
2	Peaking Plant Capacity	D10C	100.000%	32.425%	67.274%	6.105%	61.169%	54.700%	6.469%	0.000%	0.000%	0.301%
3	57% Dmd; 43% Energy: Sales & ED	D57E43	100.000%	33.347%	66.212%	5.947%	60.265%	53.477%	6.788%	0.000%	0.000%	0.441%
4	40% Dmd; 60% Energy: CIP	D99E1	100.000%	32.451%	67.244%	6.100%	61.143%	54.666%	6.478%	0.000%	0.000%	0.305%
5	Labor w/o (or w/) A&G	LABOR	100.000%	38.601%	60.078%	6.334%	53.744%	47.672%	6.072%	0.000%	0.000%	1.321%
6	Net Plant In Service	NEPIS	100.000%	39.139%	59.953%	6.169%	53.784%	47.846%	5.938%	0.000%	0.000%	0.908%
7	Dis O&M w/o Sup & Misc	OXDTS	100.000%	53.423%	37.531%	6.923%	30.608%	27.923%	2.684%	0.000%	0.000%	9.046%
8	O&M w/o Reg Ex & OXTS-Alloc'd A&G	OXTS	100.000%	36.548%	62.504%	6.074%	56.429%	49.841%	6.589%	0.000%	0.000%	0.949%
9	Production Plant	P10	100.000%	34.043%	65.412%	5.828%	59.584%	52.555%	7.029%	0.000%	0.000%	0.546%
10	Production Plant Wo Nuclear	P10WoN	100.000%	33.885%	65.593%	5.855%	59.739%	52.764%	6.975%	0.000%	0.000%	0.522%
11	Total P51 & P61A	P5161A	100.000%	33.901%	65.574%	5.852%	59.722%	52.742%	6.980%	0.000%	0.000%	0.525%
12	Distribution Plant	P60	100.000%	62.674%	33.918%	7.130%	26.788%	24.793%	1.994%	0.000%	0.000%	3.408%
13	Distr Substn Plant	P61	100.000%	36.742%	62.307%	5.525%	56.782%	50.039%	6.742%	0.000%	0.000%	0.952%
14	Line Transformer Plant	P68	100.000%	63.267%	36.284%	7.375%	28.909%	28.510%	0.399%	0.000%	0.000%	0.449%
15	Services Plant	P69	100.000%	90.942%	9.058%	3.502%	5.556%	5.556%	0.000%	0.000%	0.000%	0.000%
16	Dist Plt Overhead Lines	POL	100.000%	55.679%	40.253%	6.842%	33.410%	30.466%	2.945%	0.000%	0.000%	4.069%
17	Real Est & Property Tax	PT0	100.000%	39.8839%	59.005%	6.211%	52.793%	47.049%	5.745%	0.000%	0.000%	1.112%
18	Produc, Trans & Distrib	PTD	100.000%	38.912%	60.064%	6.110%	53.954%	47.911%	6.044%	0.000%	0.000%	1.024%
19	Dist Plt Undground Lines	PUL	100.000%	71.232%	26.476%	8.238%	18.238%	17.559%	0.679%	0.000%	0.000%	2.292%
20	Rate Base (Non-Column)	RTBASE	100.000%	38.753%	60.327%	6.153%	54.173%	48.178%	5.996%	0.000%	0.000%	0.921%
21	Stratified Hydro Baseload	STRATH	100.000%	34.248%	65.175%	5.793%	59.383%	52.282%	7.100%	0.000%	0.000%	0.577%
22	Transmission & Distrib	TD	100.000%	48.426%	49.616%	6.660%	42.956%	38.838%	4.118%	0.000%	0.000%	1.958%
23	Labor Dis w/o Sup & Eng	ZDTS	100.000%	52.499%	41.445%	7.254%	34.191%	31.122%	3.069%	0.000%	0.000%	6.056%

			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**	**Ltg**
24	Labor w/o A&G	LABOR(S)	302,489	116,764	181,728	19,158	162,570	144,203	18,367	0	0	3,997
25	Dis O&M w/o Sup, Cust Install & Misc	OXDTS	5,245	2,802	1,968	363	1,605	1,465	141	0	0	474
26	O&M w/o Reg Ex & OXTS-Alloc'd A&G	OXTS	167,164	61,095	104,484	10,154	94,330	83,316	11,014	0	0	1,586
27	Total P51 & P61A	P5161A	4,596	1,558	3,014	269	2,745	2,424	321	0	0	24
28	Produc, Trans & Distrib	PTD	811,976	315,957	487,703	49,608	438,095	389,023	49,073	0	0	8,316
29	Transmission & Distrib	TD	274,898	133,121	136,392	18,309	118,084	106,764	11,320	0	0	5,384
30	Labor Dis w/o Sup & Eng, Cust Install	ZDTS	33,985	17,842	14,085	2,465	11,620	10,577	1,043	0	0	2,058

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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**	**Ltg**
1	Customers - Ave Monthly	C11	100.00%	84.39%	13.58%	9.60%	3.97%	3.94%	0.04%	0.00%	0.00%	2.03%
2	Cust Acctg Wtg Factor	C11WA	100.00%	79.48%	20.14%	11.94%	8.20%	8.10%	0.10%	0.00%	0.00%	0.38%
3	Mo Cus Wtd By Mtr Invest	C12WM	100.00%	61.96%	36.36%	13.93%	22.42%	20.54%	1.88%	0.00%	0.00%	1.69%
4	Sec & Pri Customers	C61PS	100.00%	86.04%	13.82%	9.74%	4.07%	4.04%	0.04%	0.00%	0.00%	0.14%
5	C62Sec, w/o Ltg & C/I Underground	C62NL	100.00%	94.69%	5.31%	3.75%	1.55%	1.55%	0.00%	0.00%	0.00%	0.00%
6	Secondary Customers	C62Sec	100.00%	86.07%	13.78%	9.75%	4.04%	4.04%	0.00%	0.00%	0.00%	0.14%
7	Summer Peak Resp KW	D10S	100.00%	29.93%	70.07%	5.96%	64.11%	57.27%	6.84%	0.00%	0.00%	0.00%
8	Transmission Demand %	D10T	100.00%	33.92%	65.60%	6.19%	59.40%	53.16%	6.25%	0.00%	0.00%	0.48%
9	Winter Peak Resp KW	D10W	100.00%	39.37%	59.49%	6.51%	52.98%	47.53%	5.44%	0.00%	0.00%	1.14%
10	Alternative Production Allocator	AED4CP	100.00%	29.34%	70.32%	6.52%	63.80%	57.26%	6.54%	0.00%	0.00%	0.34%
11	Sec, Pri & TT, Class Coin kW @ Substation	D60Sub	100.00%	36.78%	62.26%	5.52%	56.74%	50.00%	6.74%	0.00%	0.00%	0.96%
12	Sec & Pri, Cl Coin kW (no Min Sys; adj Res W/)	D61PS	100.00%	32.55%	66.60%	4.93%	61.67%	54.27%	7.41%	0.00%	0.00%	0.85%
13	D62Sec, w/o Ltg & C/I Underground	D62NLL	100.00%	80.98%	19.02%	2.84%	16.19%	16.19%	0.00%	0.00%	0.00%	0.00%
14	Sec, Class Coin kW (w/o Min Sys kW)	D62SecL	100.00%	47.37%	51.96%	5.64%	46.32%	46.32%	0.00%	0.00%	0.00%	0.66%
15	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%
16	On + Off Sales MWH	E8760	100.00%	34.58%	64.79%	5.74%	59.06%	51.84%	7.22%	0.00%	0.00%	0.63%
17	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%
18	Present Rev	R01	100.00%	38.56%	60.42%	6.33%	54.08%	48.52%	5.57%	0.00%	0.00%	1.02%

			1=2+3+10	2	3=4+5	4	5=6 to 9	6	7	8	9	10
APPLIED EXTERNAL DATA			**MN**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Tr Transf**	**Trans**	**Ltg**
19	Customers - B Basis	C10	89,565	77,063	12,374	8,726	3,648	3,614	33	0	0	128
20	Cust - Ave Monthly (C10-Area Lt)	C11	91,774	77,450	12,459	8,812	3,648	3,614	33	0	0	1,865
21	Mo Cus Wtd By Cus Acct	C11WA	95,594	75,975	19,253	11,414	7,839	7,741	98	0	0	366
22	Cust Acctg Wtg Factor	C11WAF	7.35	0.98	6.37	1.30	5.07	2.14	2.93	0.00	0.00	N/A
23	Cust-Ave Mo (C11 w/ Dir Assign St Ltg)	C12	91,431	77,450	12,459	8,812	3,648	3,614	33	0	0	1,522
24	Mo Cus Wtd By Mtr Invest	C12WM	10,725,904	6,645,497	3,899,673	1,494,491	2,405,182	2,203,155	202,027	0	0	180,733
25	Meter Invest / Cust Factor	C12WMF	7,032	86	6,828	170	6,658	610	6,049	0	0	119
26	Sec & Pri Customers	C61PS	89,565	77,063	12,374	8,726	3,648	3,614	33	0	0	128
27	C62Sec, w/o Ltg & C/I Underground	C62NL	81,382	77,063	4,319	3,054	1,265	1,265	0	0	0	0
28	Secondary Customers	C62Sec	89,531	77,063	12,340	8,726	3,614	3,614	0	0	0	128
29	Summer Peak Resp KW	D10S	495	148	347	29	317	283	34	0	0	0
30	Dmd (D10S x Fact + D10W)/1000	D10T	10,000,000	3,392,295	6,559,551	619,281	5,940,269	5,315,505	624,764	0	0	48,154
31	Winter Peak Resp KW	D10W	428	169	255	28	227	203	23	0	0	5
32	Alternative Production Allocator	AED4CP	10,000,000	2,933,939	7,031,571	651,649	6,379,922	5,725,548	654,374	0	0	34,490
33	Sec, Pri & TT, Class Coin kW @ Substation	D60Sub	566,768	208,479	352,857	31,278	321,579	283,372	38,207	0	0	5,432
34	Sec & Pri, Class Coin kW (w/o Min Sys; reduced	D61PS	515,278	167,718	343,192	25,402	317,790	279,625	38,165	0	0	4,368
35	D62Sec, w/o Ltg & C/I Underground	D62NLL	778,581	630,468	148,113	22,087	126,026	126,026	0	0	0	0
36	Sec, Class Coin kW (w/o Min Sys kW)	D62SecL	10,000,000	4,737,112	5,196,472	564,431	4,632,041	4,632,041	0	0	0	66,416
37	Annual Billing kW	D99	3,581.533	0	3,582	0	3,582	3,239	343	0	0	0
38	Summer Billing kW	D99S	1,257.547	0	1,258	0	1,258	1,129	128	0	0	0
39	Winter Billing kW	D99W	2,323.986	0	2,324	0	2,324	2,109	215	0	0	0
40	Non-Coinc Pk Second	DN-Sec	1,058,016	630,468	423,181	63,105	360,075	360,075	0	0	0	4,368
41	kWh Sales @ Meter	E99	2,270,721	784,751	1,466,635	125,788	1,340,847	1,172,103	168,745	0	0	19,336

Northern States Power Company
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VOLTAGE DISCOUNT ANALYSIS - DEMAND ($/kW)

Includes losses to indicate additional billing kW low voltage customers would have at higher voltage.

	Secondary Costs	Primary Costs	
	Lines & Transformers	Lines & Transformers	Distribution Substation
1. Revenue Requirement ($000s):			
(CCOSS; p. 2; lines 33,32,31)	$1,693.266	$2,129.637	$1,744.660
2. Billing KW			
Secondary Voltage kW	3,238,674	3,238,674	3,238,674
Loss Factor	1.0000	1.0202	1.0422
Secondary With Losses	**3,238,674**	**3,304,124**	**3,375,392**
Primary Voltage kW		342,859	342,859
Loss Factor		1.0000	1.0216
Primary With Losses		**342,859**	**350,254**
Transmission Transformed Voltage kW			**0**
Total kW (Metered Sales + Losses)	**3,238,674**	**3,646,983**	**3,725,645**
3. Rev Reqt / kW (Line 1 / Line 2)	$0.5228	$0.5839	$0.4683
4. Cumulative Rev Reqt/ kW	**$0.52**	**$1.11**	**$1.58**
5. Present Individual Discounts	$0.62	$0.48	$0.30
6. Cumulative Present Discount	**$0.62**	**$1.10**	**$1.40**
7. Midpoint-Pres and Rev Reqt (Lines 4+ 6 /2)	$0.57	$1.10	$1.49
8. Cumulative Proposed Discount (Rounded to nearest $0.05)	**$0.60**	**$1.10**	**$1.50**

Northern States Power Company **Case No. PU-12-____**
Electric Utility - State of North Dakota **Exhibit___(MAP-1), Schedule 5**
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VOLTAGE DISCOUNT ANALYSIS - ENERGY (¢/kWh)

Voltage	[1] E8760 Losses	[2] Percent Difference	[3] Energy Charge	[4] Cost-Based Discount	[5] Proposed Discount	[6] Present Discount	
Secondary	10.95%	0.00%	5.652	0.0000	**0.000**	0.000	¢ per kWh
Primary	9.15%	1.80%	5.550	0.1015	**0.102**	0.095	¢ per kWh
T Transformed	7.24%	3.71%	5.443	0.2095	**0.210**	0.200	¢ per kWh
Transmission	6.75%	4.20%	5.415	0.2373	**0.240**	0.220	¢ per kWh

Service Date: December 5, 2017

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	DOCKETS UE-170033 and UG-170034 *(consolidated)* ORDER 08 FINAL ORDER REJECTING TARIFF SHEETS; APPROVING AND ADOPTING SETTLEMENT STIPULATION; RESOLVING CONTESTED ISSUES; AND AUTHORIZING AND REQUIRING COMPLIANCE FILING

Synopsis*: The Commission approves and adopts a Settlement Stipulation that all parties to this proceeding except Public Counsel support as proposed resolutions of most of the many issues initially contested. The Settlement Stipulation would establish new revenue requirements, update PSE's cost of capital, address increased depreciation expense established in connection with shortened depreciation schedules for PSE's coal-fired production assets in Colstrip, Montana, accept numerous uncontested individual revenue requirement adjustments, and resolve several individual adjustments to which Public Counsel objects, including depreciation of natural gas capital investments, pension expense, non-Colstrip environmental remediation costs, storm damage expense, and the costs of assets held for future use. The Settling Parties agreed to, and the Commission approves in this Order, an overall electric revenue increase of $20 million (1.0 percent increase) and an overall natural gas revenue decrease of $35 million (3.9 percent decrease).*

The Settlement Stipulation also addresses several contested non-revenue issues, including guidelines for a possible expedited rate filing (ERF) to update PSE's rates within 12 months after the date of this order, plans to address the continuation of the Company's water heater program, and a changed metric for PSE's Service Quality Index. Finally, the Settlement Stipulation expressly recognizes as prudent eight projects, including capital projects improving or acquiring production, distribution, and storage assets, a power purchase agreement acquiring additional hydropower, new and renewed BPA transmission contracts, and deferred non-Colstrip depreciation expense.

The Commission, in addition, resolves a number of fully contested non-revenue issues related to decoupling, class cost of service studies, rate spread, rate design, and PSE's proposed cost recovery mechanism for certain capital costs. The parties to the Settlement Stipulation agreed these issues should be reserved for decision on the basis of a fully developed record and the parties' briefing of the issues. The Commission's decisions on these issues are summarized briefly in the discussion of Commission determinations in the Summary section of this Order at paragraphs 8 – 23.

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SUMMARY

1 **PROCEEDINGS:** On January 13, 2017, Puget Sound Energy (PSE or Company) filed with the Washington Utilities and Transportation Commission (Commission) revisions to its currently effective Tariffs WN U-60, Electric Service, and WN U-2, Natural Gas Service. This is PSE's first general rate case since Dockets UE-011048/UG-011049, filed in 2011 and resolved by the Commission's Final Order in 2012.[1] PSE's rate schedules, however, have been adjusted several times since May 2012 following the Commission's approval in June 2013 of a multi-year Rate Plan.

2 The Commission's 2013 order updated the rates approved in 2011 based on a novel approach identified as an Expedited Rate Filing (ERF) that allowed limited adjustments to rates. The order also approved full decoupling for electric and natural gas rates, and the use of a so-called K-factor that provided for modest annual rate increases during the term of the Rate Plan.[2] These adjustments to the rate schedules approved in 2012 offset to a significant degree the Company's proposed increase to base rates in this case. Including the impacts of these offsets, PSE stated in its filing that the net impact to customers' rates was anticipated to be an increase in electric rates of $86,694,000 (4.1 percent) and a decrease to natural gas rates of $22,323,105 (-2.4 percent).[3]

3 The Commission, in Order 01, suspended the tariff filings on January 19, 2017, consolidated the two dockets, and determined that it would hold public hearings, as necessary, to determine whether the proposed increases are fair, just, reasonable, and sufficient.[4] The Commission held two public comment hearings, an evidentiary hearing

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[1] *WUTC v. Puget Sound Energy*, Dockets UE-011048 and UG-011049 (*consolidated*), Order 08 (May 7, 2012).

[2] *In the Matter of the Petition of Puget Sound Energy and NW Energy Coalition For an Order Authorizing PSE to Implement Electric and Natural Gas Decoupling Mechanisms and to Record Accounting Entries Associated with the Mechanisms*, Dockets UE-121697 and UG-121705 (consolidated) (Decoupling) and *Washington Utilities and Transportation Commission v. Puget Sound Energy*, Dockets UE-130137 and UG-130138 (consolidated) (ERF), Order 07 - Final Order Granting Decoupling Petition and Final Order Authorizing ERF Rates (June 25, 2013) (Order 07-2013 Rate Plan).

[3] On April 3, 2017, PSE filed supplemental testimony proposing an increase of $68.3 million, or 3.2 percent for electric, and a rate decrease of $29.3 million, or 3.2 percent for gas. On August 9, 2017, PSE filed rebuttal testimony revising its position on several issues, and incorporating the revenue requirement updates provided in its supplemental filing. The Company's rebuttal rate request was an increase of $57.9 million, or 2.8 percent for electric, and a rate decrease of $29.4 million, or 3.4 percent for gas.

[4] The suspension date for the as-filed tariffs is December 13, 2017.

on contested issues, and an evidentiary hearing concerning a contested multi-party, partial settlement.[5] The Settlement Stipulation, if approved, would resolve most issues in these dockets, including all revenue requirements issues. In this Order, the Commission makes its determinations concerning all uncontested and contested adjustments to revenue requirements and rates in this Final Order, and resolves important non-revenue and policy issues presented by the parties.

4 **PARTY REPRESENTATIVES:[6]** Sheree Strom Carson, Jason Kuzma, Donna Barnett, and Jason S. Steele, Perkins Coie LLP, Bellevue, Washington, represent PSE. Lisa W. Gafken and Armikka R. Bryant, Assistant Attorneys General, Seattle, Washington, represent the Public Counsel Unit of the Washington State Attorney General's Office (Public Counsel). Sally Brown, Senior Assistant Attorney General, and Julian Beattie, Jennifer Cameron-Rulkowski, Chris Casey, Andrew O'Connell, Jeff Roberson, and Brett P. Shearer, Assistant Attorneys General, Olympia, Washington, represent the Commission's regulatory staff (Staff).[7]

5 Patrick Oshie and Tyler Pepple, Davison Van Cleve, P.C., Portland, Oregon, represent the Industrial Customers of Northwest Utilities (ICNU). Chad M. Stokes and Tommy A. Brooks, Cable Huston, Portland, Oregon, represent the Northwest Industrial Gas Users (NWIGU). Kurt J. Boehm and Jody Kyler Cohn, Boehm, Kurtz & Lowry, Cincinnati, Ohio, represent The Kroger Company, Fred Meyer Stores, and Quality Food Centers (Kroger). Damon E. Xenopolous and Shaun Mohler, Stone Mattheis Xenopolous & Brew, PC, Washington, D.C., represent Nucor Steel Seattle (Nucor).

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[5] The Commission's procedural rules recognize multi-party settlements as those agreed to by some, but not all parties, and recognize partial settlements as those that propose to resolve some, but not all issues. WAC 480-07-730. In this case, all parties but one either support or do not oppose the settlement before us and most issues are proposed for resolution by the Settlement Stipulation. *See infra*. ¶39, which identifies the "Settling Parties."

[6] Invenergy LLC, represented by Richard H. Allan, Marten Law, Portland, Oregon, petitioned to intervene during the first prehearing conference on February 8, 2017. The Commission denied Invenergy's petition because it failed to demonstrate a substantial interest in the proceeding or that its participation would be in the public interest. TR. at 22:25-29:4; *see* WAC 480-07-355(3).

[7] In formal proceedings, such as this, the Commission's regulatory staff participates like any other party, while the Commissioners make the decision. To assure fairness, the Commissioners, the presiding administrative law judge, and the Commissioners' policy and accounting advisors do not discuss the merits of this proceeding with the regulatory staff, or any other party, without giving notice and opportunity for all parties to participate. *See*, RCW 34.05.455.

6 Simon J. ffitch, attorney, Bainbridge Island, Washington, represents The Energy Project. Travis Ritchie and Gloria D. Smith, Sierra Club Environmental Law Program, Oakland, California, represent the Sierra Club. Amanda Goodin, Kristen Boyles, and Matthew Gerhart, Earthjustice, Seattle, Washington, represent NW Energy Coalition (NWEC), Renewable Northwest, and Natural Resources Defense Counsel.[8]

7 Rita Liotta and John Cummins, U.S. Navy, San Francisco, California, represent the Federal Executive Agencies (FEA). Robert McKenna, Brian T. Moran and Adam Tabor, Orrick, Herrington & Sutcliffe, LLP, Seattle, Washington, represent the State of Montana (Montana).

8 **COMMISSION DETERMINATIONS:** We agree with the parties that the scope of this proceeding distinguishes it as one of the major complex litigations before the Commission during the past two decades. Our Order today approves a historic agreement, which addresses, among other things, many challenging issues regarding the Colstrip coal-fired power plants that the Commission and parties have grappled with for more than a decade while resulting in a modest 1 percent increase in electric rates and a nearly 4 percent decrease in natural gas rates. Ten parties propose to resolve most issues in these dockets through the terms of a multi-party, partial settlement, as those terms are defined in WAC 480-07-730. One party takes no position on the settlement. One party, Public Counsel, supports, accepts, or takes no position with respect to most of the settlement's terms, but opposes the Settling Parties' proposed resolution of rate of return on equity, a key part of the Company's capital structure that significantly affects revenue requirements. Public Counsel also partially opposes the settlement on a second key issue; the treatment of depreciation expense related to the scheduled closure of Colstrip coal-fired generation Units 1 & 2, and depreciation expense at Colstrip Units 3 & 4. Finally, in terms of revenue requirements, Public Counsel opposes the settlement on a few smaller issues. Public Counsel also opposes the settlement's proposed resolution of several non-revenue issues that would: 1) expressly allow PSE to file an update to the rates approved in this proceeding within 12 months after the date of this Order; 2) continue the Company's water heater program subject to a collaborative; and 3) adjust the measure of PSE's promptness in answering customer calls included in the Company's Service Quality Index. Considering the full record in this proceeding, including Public Counsel's testimony and argument opposing specific provisions, the Commission approves and

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[8] Identified collectively in this Order as NWEC/RNW/NRDC, for ease of reference.

adopts the Settlement Stipulation, without condition, for the reasons discussed in this Order.[9]

9 The Commission, in addition, resolves a number of non-revenue issues expressly reserved by the parties as fully contested issues. Briefly, the Commission approves the continued use of PSE's decoupling mechanisms, excluding electric Schedules 46 and 49, subject to certain modifications including increased demand charges, continued reporting requirements for four years, and another review at the end of the four year period. The Commission increases the "soft cap" for rate increases that result from natural gas decoupling for four years; removes normalizing adjustments from the earnings test; rejects a proposed dead band for the earnings sharing mechanism; and refines the grouping of non-residential electric and natural gas customers taking service under certain rate schedules.

10 The Commission rejects PSE's proposed Electric Cost Recovery Mechanism.

11 Although not part of the Settlement Stipulation, all parties except Public Counsel ultimately agreed to use PSE's class cost of service study (CCOSS) for electric rate spread and rate design. We require PSE to follow the terms of the Rate Design Settlement in Docket UE-141368, including use of the 4-Coincident Peak (CP) allocation factor for demand-related production and transmission costs, and the classification of 25 percent of production costs as demand and 75 percent as energy. We reject Public Counsel's proposal to treat fuel costs as 100 percent energy, contrary to the Rate Design Settlement to which Public Counsel is a party. We accept adjustment of Schedule 35 (irrigation) by 150 percent of the system average percentage increase because it is significantly out of parity, adjustment of non-residential schedules that are at higher than 108 percent of parity by 65 percent of the system average increase, and adjustment of all schedules that are within 10 percent of parity by the system average increase.[10]

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[9] The Settlement Stipulation is attached to, and made a part of, this Order as Appendix B.

[10] We emphasize here that parties who contend the Commission has established 10 percent out of parity as a criterion for what is acceptable are incorrect. In principle, each customer class should pay exactly 100 percent of the costs it causes PSE to incur. Were this achieved for all customer classes it would eliminate any cross-subsidization between customer classes. In practice, parity is rarely, if ever, achieved because there simply are too many variables at play and the relationships among them are dynamic, not static. In one prior case, the Commission determined that parity ratios in the range of 97 percent to 107 percent of full parity do not require rate spread adjustments, taking into account principles of gradualism and rate stability. *See WUTC v. PacifiCorp, Docket UE-100749, Order 06, ¶ 316 (March 25, 2011).* In Pacific Power's 2015

12 We reject PSE's proposed increased basic charges for residential electric customers and Staff's proposed minimum bill considering that both proposals depend on our accepting that transformer costs should be recovered in this way instead of as part of the distribution rates subject to decoupling. We see no reason to change the recovery of these costs from what is currently in place. We also reject Staff's proposed seasonal rates finding persuasive PSE's argument that the limited benefits of Staff's proposal is outweighed by the complexity and cost of implementation. We may wish to revisit possible changes to residential rate design as PSE moves toward adoption of advanced metering infrastructure, or AMI.

13 We accept NWEC/RNW/NRDC's proposal to convene another technical conference on the subject of 3-tier residential rate design, finding unacceptable PSE's failure to follow the requirements of the settlement agreement in Docket UE-141368.

14 With respect to residential electric rate design, we will not at this time require development of a net metering rate schedule. We also reject Public Counsel's suggestion that PSE's bills are insufficiently informative. Finally, we find Public Counsel's recommendations concerning the automatic application of outage credits, as proposed by Ms. Alexander's testimony, infeasible.

15 In terms of non-residential rate design, we expressly approve several settled or uncontested changes, as PSE requests. Specifically, we approve increased demand charges for Schedules 46 and 49, changes to lighting rates as proposed by PSE and Staff,

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general rate case, with reference to Docket UE-100749, the Commission noted in its Final Order that:

> A COSS uses precise math to follow elaborate cost assignments. Commission practice considers the error or range of accuracy to be +/-0.05. In other words, COSS results within the range 0.95 to 1.05 are considered within the precision of the COSS. A parity ratio of 0.90 means that the utility is collecting 90 percent of the revenue needed to cover the cost of serving that customer class, or put another way, that customer class is not paying its full share of costs. A parity ratio of 1.10 means that the utility is collecting 110 percent of the revenues needed to serve that customer class, or put another way, that customer class is paying more than needed to cover its share of costs.

WUTC v. Pacific Power & Light Company, Docket UE-152253, Order 12 ¶ 225 n 350 (September 1, 2016). *See also WUTC v. Pacific Light and Power Company*, Docket UE-130043, Order 05 ¶ 244 (December 4, 2014) (Considering that rate schedules other than street lighting were within 10 percent of parity, the parties agreed in a settlement that any revenue requirement increase should be applied as a uniform percentage increase for all rate schedules, except street lighting, which should receive no increase).

and simplification of pricing for Power Supplier Choice and Retail Wheeling service under Schedules 448 and 449, as proposed by PSE.

16 We approve of PSE's updated classification and allocation of gas costs that is undisputed in this proceeding. We direct PSE to use this updated classification and allocation in future PGA filings.

17 We accept PSE's peak and average methodology for allocating the costs of gas distribution mains 67 percent based on design day peak and 33 percent based on average throughput. We reject NWIGU's proposal to use only coincident demand because we believe this ignores the way customers use the system. We reject Staff's proposal to allocate peak demand on the average class use in the highest five-day period for each of the last three years because it places too much emphasis on how the system is used, as opposed to how it is designed.

18 We approve PSE's proposed natural gas rate spread that would (i) apply the system average increase to those classes with parity percentages between 90 percent and 110 percent (Schedules 23, 16, 53, 41, 41T, 85 and 85T); (ii) apply 50 percent of the average increase to those classes between 110 and 150 percent of parity (Schedules 86 and 86T); (iii) apply no increase to those above 150 percent of parity (Schedules 71, 72 and 74); and (iv) apply 150 percent of the average increase to those below 90 percent of parity (Schedules 31, 31T, 87 and 87T).

19 The Commission agrees with NWIGU that we should not express in this Order preferences concerning the cost of service methodologies used in this proceeding. The Commission will maintain the status quo and allow all parties the opportunity to continue participating in the generic proceedings the Commission initiated in Dockets UE-170002 and UG-170003 to develop clear guiding principles for cost of service studies to be used in future rate cases.[11]

20 The Commission will also maintain the status quo in terms of the treatment of Special Contracts. We reject Staff's proposals to change fundamentally the Commission's long-standing principles governing Special Contracts.

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[11] *See Washington Utilities and Transp. Comm'n v. Avista Corp.*, Dockets UE-160228 and UG-160229, Order 06 (Dec. 15, 2016) at ¶¶ 94-100.

21 We accept PSE's proposal to raise the natural gas residential basic charge to $11 per month. This acknowledges that actual costs may be a good bit higher, but recognizes the principle of gradualism that also guides our decision.

22 We approve PSE's proposals to apply its Gas Procurement Charge to Schedules 31 and 41, and to eliminate this charge for Schedules 31T and 41T. This will align better with the rate structure of the interruptible sales schedules that have a similar charge and eliminate confusion with respect to the transportation schedules.

23 Finally, we reject PSE's proposals to implement annual maximum volume limitations on Schedules 41 and 41T, effectively requiring customers exceeding these volume limits to take service on Schedule 85 or 85T; to eliminate the existing annual minimum load charge on Schedules 85 and 85T; to charge fully-firm customers on Schedules 85 and 85T based on their actual demands; and to relieve gas sales customers receiving fully-firm service of the obligation to sign a separate customer agreement for service under these schedules.

MEMORANDUM

I. Background and Procedural History

24 As summarized briefly above, PSE filed on January 13, 2017, its first general rate case since 2012.[12] PSE based its revenue requirements requests for electric and natural gas operations on a test year from October 1, 2015, through September 30, 2016. PSE asked in its filing for approval of an overall rate of return (ROR) of 7.74 percent,[13] based on a capital structure consisting of 48.5 percent equity and 51.5 percent debt,[14] a return on

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[12] *See WUTC v. Puget Sound Energy, Inc.*, Dockets UE-011048 and UG-011049 (*consolidated*), Order 08 (May 7, 2012).

[13] Lohse, Exh. BJL-1T at 2:5-10. This compares to the Company's currently approved ROR of 7.77 percent.

[14] Actual average test year capital structure included 48.9 percent equity and 51.1 percent debt. Doyle, Exh. DAD-1T at 36:7, Table 6. We note, however, Mr. Lohse's testimony, later adopted by Mr. Doyle, that PSE's effective rate year capital structure includes 1.0 percent short-term debt plus 3.3 percent in floating rate Junior Subordinated Notes for a total short-term debt equivalent of 4.3 percent. Lohse, Exh. BJL-1T at 3:1-16. Mr. Lohse said long-term debt in the rate year will be 47.2 percent. Thus, total debt equals 51.5 percent, as the Company proposed in this case. *Id.*

equity (ROE) of 9.80 percent,[15] long-term debt costs of 5.73 percent, [16] and short-term debt costs of 3.06 percent. [17]

25 PSE's filing reflected the Company's commitment to decommission Colstrip Units 1 & 2, approximately 614 MW of coal-fired generation located in Montana, of which PSE is a 50 percent owner.[18] The retirement date will be no later than July 1, 2022.[19] PSE agreed to this commitment as part of the settlement of a lawsuit brought by the Sierra Club and Montana Environmental Information Center in 2013 against Colstrip's owners alleging violations of the Clean Air Act. A Montana district court approved the settlement during 2016. Decommissioning and remediation costs for Colstrip Units 1 & 2 are estimated at approximately $103 million in today's dollars.[20]

26 With the agreement to retire Colstrip Units 1 & 2, PSE commissioned a full depreciation study related to Electric, Gas, and Common plant as of September 30, 2016. Specifically regarding Colstrip Units 1 & 2, the study moved the depreciable life from 2035 to the anticipated retirement date in mid-2022.[21] The Company sought authorization from the Commission in this proceeding to repurpose certain Treasury Grant funds on its books and to use existing Production Tax Credits, when monetized, to offset the anticipated decommissioning and remediation costs and the increased depreciation expense for these units rather than passing back these government benefits to customers in other ways. PSE stated its intent was to mitigate the negative rate impacts and intergenerational inequities that would likely otherwise occur as a result of closing Colstrip Units 1 & 2 in the relative near term.

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[15] Doyle, Exh. DAD-1T at 34:11. This is the same as the Company's currently approved ROE. *See also* Morin, Exh. RAM-1T at; Lohse, Exh. BJL-1T at 2:9:10, Table 1.

[16] Lohse, Exh. BJL-1T at 2:9:10, Table 1.

[17] *Id.*

[18] Talen Energy, which owns the other 50 percent of Colstrip Units 1 & 2, also is committed to the retirement of these units. Roberts, Exh. RJR-1CT at 34:1-35:9.

[19] PSE owns a smaller share of Colstrip Units 3 & 4, which have a combined capacity of about 1,480 MW. No decommissioning date has been established for these assets.

[20] Roberts, Exh. RJR-1CT at 54:8-13.

[21] The 2035 retirement dates for purposes of depreciation was established by a Commission order approving a settlement agreement in PSE's 2007 general rate case. PSE proposed in that case a 2019 retirement date but agreed in settlement to Public Counsel's and Staff's arguments that the date should be extended to 2035. *See WUTC v. Puget Sound Energy, Inc*., Dockets UE-072300 and UG-072301 (*consolidated*), Order 12, ¶ 57 (October 8, 2008).

27 PSE's depreciation study also moved up the end date for depreciation of Colstrip Units 3 & 4 to 2035, from 2044 and 2045, respectively. This was based on PSE's view that 2035 represented a "probable retirement date" for these units.[22]

28 In terms of other adjustment to revenue requirements, PSE proposed a significant number of restating and pro forma adjustments such as: weather normalization, pro forma capital expense, labor costs, pension plan expenses and compensation and benefit costs, environmental remediation costs, and storm damage costs. Many of these proposed adjustments are now uncontested by any party, but a few remain in dispute.

29 Other notable issues in PSE's as-filed case included proposed increased funding for the Company's Home Energy Lifeline Program (HELP) available to eligible low-income customers; modifications to the Company's decoupling mechanisms; a power cost update; the entrance of PSE into the CAISO Energy Imbalance Market (EIM); a proposed electric cost recovery mechanism (ECRM); a proposal to formalize the ERF process as an alternate form of ratemaking to address potential attrition and regulatory lag issues; and issues related to service quality and customer relations.

30 PSE proposed to use the results of its electric, and natural gas CCOSS to inform rate spread and rate design recommendations. These studies use very similar methodologies to what the Company relied on in its 2011/2012 general rate case.[23] Mr. Piliaris testified that PSE's proposed rate spread is based on the desire to move gradually towards full parity among customer classes.[24] PSE proposed increases to basic charges for both residential electric and natural gas customers, and increased demand charges for non-residential gas customers.

31 On April 3, 2017, PSE filed, without objection, supplemental direct testimony providing several updates including: power costs, storm damage expenses, contingent calculations for the anticipated effects of the Microsoft Retail Wheeling settlement then pending in Docket UE-161123,[25] corrections for minor errors, and updated compensation and benefit expenses. The Company's supplemental rate request proposed an increase of

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[22] Spanos, Exh. JJS-1T at 9:9-10.

[23] The 2011 PSE general rate case is the most recent rate case in which the Company's cost of service was reviewed.

[24] A rate schedule reaches parity when its proportionate share of total revenue requirement is collected from the customers in that rate schedule. This is a parity ratio of 1.0, most often expressed in terms of the customer class being at 100 percent parity.

[25] *See WUTC v. Puget Sound Energy*, Docket UE-161123, Order 06 Approving Settlement Agreement (July 13, 2017).

$68.3 million, or 3.2 percent for electric, and a rate decrease of $29.3 million, or 3.2 percent for gas. These requests did not include the contingency calculations for the Retail Wheeling settlement, which was not filed until April 11, 2017.

32 Commission Staff, Public Counsel, ICNU, Kroger, FEA, the Energy Project, Sierra Club, NWEC/RNW/NRDC, and NWIGU filed response testimonies and exhibits opposing the Company's rate and revenue requests, and addressing numerous other issues, on June 30, 2017. The parties' updated issues list submitted to the presiding officers on August 4, 2017, identified 111 issues concerning electric operations, 69 issues concerning natural gas operations, and five service quality and customer service issues.

33 The Commission held the first of two planned public comment hearings in Bellevue, Washington, on July 31, 2017, and heard comments from numerous members of the public.

34 On August 9, 2017, PSE filed rebuttal testimony revising its position on several issues, and incorporating the revenue requirement updates provided in its supplemental filing. The Company's rebuttal case proposed an increase of $57.9 million, or 2.8 percent for electric, and a rate decrease of $29.4 million, or 3.4 percent for gas.

35 Also on August 9, 2017, the parties filed their cross-answering testimonies and exhibits concerning select issues raised by Staff, Public Counsel, and various intervenors in their response testimonies. The State of Montana filed testimony on August 9, 2017, that it styled as cross-answering testimony. Staff and ICNU objected that Montana's filing was untimely and inadmissible into the evidentiary record because it should have been filed by the June 30, 2017, deadline for response testimony, and for other reasons. The Commission, in Order 07, sustained these objections and ruled that it would not accept the State of Montana's testimony into the evidentiary record. Order 07, however, acknowledged Montana's filing as a statement of the state's interests and accepted it for that purpose.

36 On August 25, 2017, several parties, including PSE and Staff, informed the presiding officers that most parties had reached a settlement in principle concerning most of the issues in this proceeding. In subsequent discussions, the parties informed the Commission that most issues in the case were resolved insofar as they were concerned, but they identified specifically several issues, largely concerning cost of service (COS), rate spread, rate design, and related matters (*e.g.,* decoupling and PSE's proposed electric cost recovery mechanism) that remained unresolved and would require Commission determination based on a full evidentiary record. NWIGU represented at the time that it would contest the settlement and also would contest at least certain of the issues remaining more broadly in dispute among the parties. Public Counsel did not state at the time a position supporting or opposing the settlement.

37 The Commission conducted evidentiary hearings at its headquarters in Olympia, Washington, on August 30, 2017, on the issues identified by the parties as being contested. [26] It admitted all prefiled testimony and exhibits as well as all previously submitted cross-examination exhibits relevant to the contested issues.[27]

38 The Commission held its second public comment hearing in Olympia, Washington, on August 31, 2017. Over the course of the proceeding, including the two public comment hearings, the Commission and Public Counsel received 495 comments regarding the proposed rate increases from Washington customers, with 432 comments opposing the increases, seven comments supporting the increases, and 56 comments neither supporting nor opposing. Notably, the Commission received numerous comments submitted by residential customers urging PSE to move away from coal-fired power even if there is additional cost associated with this move.[28] We note, in fairness, that other customers supporting Colstrip's early closure objected to the increased cost in rates.

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[26] Public Counsel informed the Commission that it remained unsure of its position on the settlement. On September 11, 2017, Public Counsel filed a letter with the Commission stating it would not join in the settlement and wished an opportunity to present an "alternative viewpoint."

[27] PSE objected to Exhibit JAP-60X, identified as a cross-examination exhibit by ICNU. The exhibit was admitted not for the truth of what it asserted, but only as an illustrative exhibit for convenience of reference. TR. 305:6-306:8.

[28] *See* Public Comment Exh. BR 5. By way of examples:

Kent and Maureen Canny followed up their participation in our Bellevue public comment hearing with an email stating in part:

> We, too, hope that you adjust PSE's payment schedule for the Colstrip facility so that the two units are retired by at least 2025!
>
> Many others spoke very eloquently about getting off coal and onto renewable sources of energy. We wholeheartedly support those statements and hope that this happens as soon as possible Thank you for your reasoned decisions as you "protect the people of Washington by ensuring that investor-owned utility and transportation services are safe, available, reliable and fairly priced.

F. Aglow, another PSE customer, commented via the internet that "I am writing to you UTC commissioners to advocate for PSE to pay off and close the remaining coal-fired units in Colstrip, Montana, by the year 2025." This commenter later added via email:

> Besides retiring the two Colstrip Montana coal units and replacing them, I'd like to ask the following:

39 On September 15, 2017, PSE, Staff, ICNU, FEA, Kroger, Energy Project, Sierra Club, State of Montana and NWEC/RNW/NRDC filed their partial settlement proposing resolution of all issues except the expressly reserved contested issues heard on August 30, 2017. NWIGU joined the settlement reserving its rights with respect to contested issues related principally to natural gas cost of service, rate spread, and rate design. We refer to these 10 parties collectively as "Settling Parties." Nucor Steel neither supported nor opposed the settlement. Public Counsel earlier informed the Commission by letter filed on September 11, 2017 that it "has not joined the multiparty settlement" and would "present an alternative viewpoint for the Commission's consideration."

40 Also on September 15, 2017, the Settling Parties filed their Joint Memorandum in Support of Multiparty Partial Settlement. PSE, ICNU and NWIGU jointly, and Sierra Club filed testimony in support of the settlement. On September 18, 2017, FEA, Staff, Energy Project, Kroger, and NWEC/RNW/NRDC filed testimony in support of the settlement. The State of Montana filed a letter in support of the settlement. On September 22, 2017, Public Counsel filed testimony opposing the settlement.

41 The Commission conducted a settlement hearing on September 29, 2017, to receive evidence and statements from the parties both supporting and opposing the Settlement Stipulation.

42 Altogether, the record includes 748 exhibits admitted, including prefiled testimony from 55 witnesses, all of whom were available for cross-examination during the evidentiary hearings, as appropriate.[29] The transcript of this proceeding is approximately 625 pages in length.

43 The parties filed initial post-hearing briefs on October 18, 2017, and reply briefs on October 27, 2017.[30]

--I'd like a firm timeline for retiring the 3rd and 4th Colstrip units by 2025 AND a decision to replace units 100% with efficiency increases and renewable sources.

[29] The one exception being PSE witness Mr. Lohse who left the Company prior to hearing. Mr. Doyle, PSE's Senior Vice President and Chief Financial Officer, adopted Mr. Lohse's testimony as his own and was available to be cross-examined concerning its substance. Doyle, TR. 171:8-18. All parties had the opportunity to identify witnesses they wished to cross-examine concerning prefiled direct testimony, response testimony, cross-answering testimony, rebuttal testimony, and settlement testimony.

[30] Public Counsel expressly supported in its Initial Brief many significant terms included in the Settlement Stipulation, expressly accepted additional terms, and took no position with respect to many other terms. Public Counsel nevertheless exercised what it described as a right to express

II. PSE's 2013 Rate Plan

44 The passage of more than five years since the Commission approved rates for PSE in Dockets UE-111048 and UG-111049 makes it appropriate, for purposes of context, to review briefly the history of PSE's rates since that time. Specifically, we discuss below the effects of the Commission's 2013 approval, in joint proceedings involving four dockets, of an update to the Company's rates, a decoupling mechanism, and a multi-year Rate Plan.

45 The Commission entered Order 07, its Final Order in Dockets UE-130137, *et al.*, on June 25, 2013.[31] Order 07 approved several innovative ratemaking mechanisms to address the Commission's policy goal of breaking the pattern of almost continuous rate cases for PSE. These mechanisms included:

- An Expedited Rate Filing (ERF) process to implement a $31.9 million (1.6 percent) electric delivery revenue increase and a $1.2 million (0.1

"alternative viewpoints" with respect to two key issues and several less significant issues, and wished to have its alternative viewpoints considered as opposition to these specific terms and as alternative results with respect to the issues addressed. Public Counsel's position with respect to the settlement in general is unclear. On the one hand, Public Counsel states (incorrectly) that "the Commission only allows binary positions with respect to settlements: support or opposition." IB ¶6. On the other hand, Public Counsel says, two sentences later, that it "recommends that the Commission adopt certain terms and modify other terms of the Settlement in setting Puget Sound Energy's (PSE or Company) rates in this proceeding." IB ¶7. It appears that Public Counsel recognizes that parties' choices in Commission proceedings are not "binary;" a party can offer partial opposition to a settlement while accepting other parts, as Public Counsel did in this case.

[31] *In the Matter of the Petition of Puget Sound Energy and NW Energy Coalition For an Order Authorizing PSE to Implement Electric and Natural Gas Decoupling Mechanisms and to Record Accounting Entries Associated with the Mechanisms*, Dockets UE-121697 and UG-121705 (consolidated) (Decoupling) and *Washington Utilities and Transportation Commission v. Puget Sound Energy*, Dockets UE-130137 and UG-130138 (consolidated) (ERF), Order 07 - Final Order Granting Decoupling Petition and Final Order Authorizing ERF Rates (June 25, 2013) (Order 07-2013 Rate Plan). ICNU and Public Counsel appealed Order 07 in Thurston County Superior Court, Case Nos. 13-2-01576-2 and 13-2-01582-7 *(consolidated).* The Superior Court entered its order on July 25, 2014, Granting in Part and Denying in Part Petitions for Judicial Review. The Court remanded this case to the Commission "for further adjudication," finding the ERF to be flawed procedurally because the Commission did not comprehensively review PSE's market cost of equity as of early 2013 in the context of the multi-year Rate Plan. Considering the overall framework of the actions it took in Order 07 and taking additional evidence as the Court directed, the Commission's order on remand left the previously approved "innovative rate mechanisms" in place and determined the Company's cost of equity as of early 2013 to be 9.8 percent, which was the same cost of equity allowed by Order 07. *Id.,* Orders 15 (Decoupling) and 14 (ERF) (June 29, 2015).

percent) gas delivery revenue reduction.[32] The limited purpose of the filing was to update PSE's delivery services costs established in May 2012 in Dockets UE-111048 and UG-111049.[33]

- Approval of a joint petition by PSE and NWEC/RNW/NRDC seeking authority to implement full decoupling of electric and natural gas rates.

- Approval of a Rate Plan that allowed for modest annual increases in PSE's rates while requiring that the Company not file a general rate increase before April 1, 2015, at the earliest.

46 Under the Rate Plan, however, PSE was required to file a general rate case by April 1, 2016. Following a hearing on a motion to amend Order 07, the Commission relieved PSE of this obligation and instead required the Company to file a general rate case no later than January 17, 2017. One key purpose of the general rate case filing requirement was to provide the Commission an opportunity to examine fully the results achieved following implementation of the several mechanisms identified above. It is appropriate, then, to provide here a brief summary of those results during the Rate Plan effective period since June 2013.

47 Mr. Doyle discussed in his direct testimony the results of decoupling, the earnings sharing mechanism, the expedited rate filing, and annual K-factor increases since they were instituted by approval of PSE's compliance filing in July of 2013. He discusses, in addition, certain cost management and efficiency efforts at PSE during the period since that time, as contemplated by the Commission when it approved these mechanisms in the context of the multi-year Rate Plan.[34]

48 In terms of overall results, Mr. Doyle testified that the Rate Plan resulted in the following financial results:

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[32] These amounts were subsequently revised to $31,138,511 for electric and $1,717,826 for natural gas to adjust for lower long-term debt costs.

[33] *WUTC v. Puget Sound Energy, Inc.,* Dockets UE-111048 and UG-111049 (*consolidated*), Order 08 (May 7, 2012).

[34] The Commission stated in Order 07-2013 Rate Plan ¶ 22 that:

> This multi-year Rate Plan will provide the Company with ample opportunity to implement efficiencies that will afford the Company with the earnings opportunities it seeks. And these cost savings, which we will monitor carefully, will then be incorporated into rates for the benefit of ratepayers.

- An approximate $30 million net electric and gas rate increase from the expedited rate filing in July 2013.
- Annual K-factor increases to delivery revenues of 3.0 percent for electric and 2.2 percent for gas in July 2013, January 2014, January 2015, January 2016, and January 2017.
- Recognition of net electric decoupling revenue of approximately $59 million and net gas decoupling revenue of approximately $116 million from July 1, 2013, through September 30, 2016.

These financial results, coupled with cost savings and efficiencies realized during the Rate Plan effective period, "allowed PSE to begin to consistently earn rates of return and returns on equity slightly below its authorized rate of return and return on equity on an adjusted actual basis across all time periods."[35] According to Mr. Doyle, these results show that the Rate Plan mitigated the effects of regulatory lag and attrition during the Rate Plan effective period.[36]

49 Mr. Doyle presented in his testimony two tables, reproduced here, which provide comparisons of adjusted actual and normalized rates of return and returns on equity to reflect actual results for electric and natural gas operations during the period from 2011 through calendar year 2016.

Table 1. Comparison of PSE's Adjusted Actual and Normalized Rates of Return and Returns on Equity for Electric Operations

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Rate of Return			Return on Equity		
	Year	Adjusted Actual (2)	Normalized (3)	Authorized	Adjusted Actual (2)	Normalized (3)	Authorized
1	2016 (1)	7.76%	7.99%	7.77%	9.66%	10.13%	9.80%
2	2015	7.52%	8.05%	7.77%	9.13%	10.25%	9.80%
3	2014	7.53%	7.74%	7.77%	9.01%	9.44%	9.80%
4	2013	7.50%	7.56%	7.77%	8.95%	9.06%	9.80%
5	2012	7.46%	7.14%	7.80%	8.78%	8.11%	9.80%
6	2011	7.75%	6.62%	8.10%	9.31%	6.98%	10.10%

Notes:
(1) 12 months ended June 30, 2016

(2) Adjusted actual returns: Exclude ASC 815 (formerly FAS 133) gains or losses and include tax benefits of interest
(3) Normalized returns: 2011 - 2016 (June) CBR filed with WUTC

[35] Doyle, Exh. DAD-1T at 3:1-17.

[36] Doyle, Exh. DAD-1T at 3:17-18.

Table 2. Comparison of PSE's Adjusted Actual and Normalized Rates of Return and Returns on Equity for Gas Operations

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Rate of Return			Return on Equity		
	Year	Adjusted Actual (2)	Normalized (3)	Authorized	Adjusted Actual (2)	Normalized (3)	Authorized
1	2016 (1)	8.16%	8.44%	7.77%	10.49%	11.06%	9.80%
2	2015	7.62%	8.17%	7.77%	9.34%	10.49%	9.80%
3	2014	7.80%	7.87%	7.77%	9.56%	9.71%	9.80%
4	2013	7.22%	7.34%	7.77%	8.37%	8.62%	9.80%
5	2012	7.99%	7.46%	7.80%	9.87%	8.78%	9.80%
6	2011	9.19%	6.78%	8.10%	12.25%	7.30%	10.10%

Notes:
(1) 12 months ended June 30, 2016
(2) Adjusted actual returns: Exclude ASC 815 (formerly FAS 133) gains or losses and include tax benefits of interest
(3) Normalized returns: 2011 - 2016 (June) CBR filed with WUTC

50 Mr. Doyle identified four principal ways in which PSE achieved cost management efficiencies during the Rate Plan period:

- PSE aligned its growth rate in operating expenses with customer growth to set annual operating and maintenance budgets.[37]
- PSE restructured its benefit plans, slowing the increase in costs associated with employee benefit programs.
- PSE implemented additional efficiencies related to debt refinancings, bonus depreciation elections, efficiencies from certain lobbying activities to change the normalization requirements for treasury grants, and reduced to the extent possible the cost of decommissioning and remediating Colstrip Units 1 & 2.

51 Mr. Doyle testified that PSE implemented a broad-based approach to manage its operating expenditures, following a guideline aimed at having growth in budgets and spending align with the rate of customer growth. Specifically, PSE managed its actual operating expenditures, on a combined basis, to achieve a compound average growth rate of approximately 1.2 percent from 2011 to 2016. According to Mr. Doyle, relying on Ms. Barnard's testimony, this equates to a compound average customer growth rate on a combined basis of 0.8 percent over the same timeframe. Mr. Doyle testifies that "[t]his is an extremely positive result given that (i) PSE's approved operating expense growth rate from 2006 to 2011 was approximately 3.8%, and (ii) general inflation from 2011 to 2016

[37] Doyle, Exh. DAD-1T at 26:15-18.

was 1.2%."[38] This compares favorably to PSE's historical operating expense growth rate of 3.8 percent, which, if sustained through the Rate Plan period, would have resulted in an additional $136 million in operating expenses.

52 In summary, in terms of cost savings over the course of the Rate Plan, PSE:

(i) Estimates that it saved approximately $136 million against historical operational spending trends through its efforts to limit growth in operational spending to the rate of customer growth.

(ii) Saved $19.3 million annually through refinancings and managing its capital structure.

(iii) Saved $23.7 million through its voluntary bonus depreciation elections and resulting rate base reductions, which will continue into the future.

(iv) Provided customers $65.9 million in interest credits through September 2016 associated with the Lower Snake River wind farm Treasury Grants related to the elimination of normalization requirements for Treasury Grants, an effort which also made it possible to repurpose Treasury Grants to offset future Colstrip Units 1 & 2 decommissioning and remediation costs. Similar benefits exist with respect to Wild Horse wind farm Treasury Grants in the amount of $8.1 million.

(v) Will save customers an estimated $71.2 million nominally and $49.5 million on a net present value basis through the repurposing of certain Treasury Grants and Production Tax Credits to offset future Colstrip Units 1 & 2 decommissioning and remediation costs.

(vi) Agreed to participate in the CAISO Energy Imbalance Market providing future power cost savings.

(vii) Restructured certain benefit plans. The operating expense portion of those savings are included in the $136 million discussed in (i) above. The capital component is "netted" in PSE's rate base in this proceeding. PSE expects these savings to continue into the future as well.[39]

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[38] Doyle, Exh. DAD=1T at 27:18-28:3 (citing Barnard, Exh. KJB-1T).

[39] Doyle, Exh. DAD-1T at 33:3-34:7.

53 It is in this context that PSE filed its 2017 general rate case that is the subject of our Final Order here.

III. Present Posture of PSE's 2017 General Rate Case

54 As previously summarized, the 12 parties that participated in these dockets identified 185 issues at the time response testimony was filed on June 30, 2017. The Commission received five sets of prefiled testimony from 55 witnesses (*i.e.,* direct and supplemental from PSE, response from Staff, Public Counsel, and nine intervenors, rebuttal from PSE, and cross-answering from Staff, Public Counsel, and seven intervenors).[40] The parties filed numerous exhibits supporting their witnesses' narrative testimonies. The Commission thoroughly reviewed the prefiled testimony and exhibits in preparation for a multi-day evidentiary hearing scheduled to begin on August 29, 2017. Then, the posture of the case changed when late in the day on Thursday, August 25, 2017, counsel for PSE, Staff, and ICNU gave informal notice that they had reached a settlement in principle concerning all contested revenue requirements issues for electric operations and were actively soliciting support from additional parties.

55 The parties continuing efforts over the next 24 hours informed an email from Staff counsel to the presiding administrative law judges and all parties' representatives at the close of business on Friday, August 26, 2017. Staff counsel related that "PSE, Staff, Kroger, Sierra Club, NWEC, and The Energy Project have agreed to a partial settlement. Four additional parties are still in the process of reviewing the settlement and intend to make a final decision by Monday. One party has indicated it will not support the settlement."

56 Staff counsel's email stated that the parties' agreement in principle left only a discrete set of fully contested issues concerning electric operations, as follows:

[40] As noted above in ¶ 33, the Commission received testimony from the State of Montana as part of the general record of this proceeding as a statement of the state's interests, but not as part of the evidentiary record for decisions.

- Electric Cost Recovery Mechanism.
- Decoupling, except for the parties' agreement to accept Staff's proposal for treatment of fixed production costs.
- Electric rate spread and rate design with five specific exceptions identified in Staff counsel's email.

57 Staff counsel also stated that none of the issues concerning natural gas rate spread and rate design had been settled. Thus, in something of a mirror image to the circumstances six years earlier in Dockets UE-111048/UG-111049, it appeared from Staff counsel's email that the settlement would propose agreed outcomes for revenue requirements issues while reserving for full litigation issues concerning cost of service, rate spread, and rate design for both electric and natural gas services.

58 The Settling Parties proposed without objection, and the Commission agreed, to proceed with its evidentiary hearing on August 30, 2017, instead of August 29, 2017, for the purpose of cross-examination of witnesses whose testimony concerned the issues that would require decisions by the Commission based on the evidentiary record and the parties' advocacy in briefs. Ten witnesses were individually sworn and made available for cross-examination. The parties agreed to stipulate into the record all prefiled testimony and exhibits from all witnesses, and all but one of the cross-examination exhibits identified for the 10 witnesses.[41] The one exhibit to which a party objected was admitted later as an illustrative exhibit.[42]

59 On September 15, 2017, PSE, Staff, ICNU, FEA, Kroger, Energy Project, Sierra Club, State of Montana, NWEC/RNW/NRDC, and NWIGU filed their Settlement Stipulation and a joint narrative statement in support. The State of Montana filed a letter supporting the settlement. Settling Parties filed individual party testimonies on September 15 and 18, 2017. Public Counsel filed testimony opposing the settlement, in part, on September 22, 2017.

60 Public Counsel's witness Colamonici testified that Public Counsel *supported* the discontinuance of Schedule 40.[43] She said further that Public Counsel *supported* the Settlement Stipulation's terms concerning low-income issues, decoupling, and the

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[41] TR. 157:13 - 159:9.

[42] TR. 305:6 - 306:7

[43] Colamonici, Exh. CAC-1T at 5:14. *See* Settlement Stipulation ¶96.

Colstrip Reporting Requirements, Operational Study, and Workshop.[44] Ms. Colamonici also testified that Public Counsel *accepted* the Settling Parties' proposed resolution of 10 revenue requirements issues, and was *neutral* with respect to the Settling Parties' proposed resolution of 18 additional revenue requirements issues.[45] The Commission conducted a settlement hearing on September 29, 2017. The parties filed initial and reply briefs on October 18 and 27, 2017, respectively.

61 Considering the changed posture of this proceeding, we observe for the sake of clarity that our responsibility is no less in a case such as this where most, but not all, parties have negotiated a settlement agreement covering most, but not all, issues, than in a case in which most issues are fully litigated, with only a few issues settled, such as in PSE's 2011/2012 general rate case.[46] The Commission's process for considering settlements is spelled out in WAC 480-07-740, which provides among other things that:

> Each party to a settlement agreement must offer to present one or more witnesses to testify in support of the proposal and answer questions concerning the settlement agreement's details, and its costs and benefits. Proponents of a proposed settlement must present sufficient evidence to support its adoption under the standards that apply to its acceptance. Counsel must make a brief presentation of the settlement, and address any legal matters associated with it. Counsel must be available to respond to questions from the bench regarding those subjects.

WAC 480-07-740(2)(b), and

> Parties opposed to the commission's adoption of a proposed settlement retain the following rights: The right to cross-examine witnesses supporting the proposal; the right to present evidence opposing the proposal; the right to present argument in opposition to the proposal; and the right to present evidence or, in the commission's discretion, an offer of

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[44] Colamonici, Exh. CAC-1T at 13:2-6. *See* Settlement Stipulation ¶¶102-111 (low-income); ¶¶113-14 (decoupling); ¶¶119-21 (Colstrip issues).

[45] Public Counsel did not address, and therefore is deemed to have not contested one additional settled revenue requirements issue, Investor Supplied Working Capital.

[46] In the prior case, the parties settled only issues related to cost of service, rate spread, and rate design. Revenue requirements issues and, hence, rates, remained in dispute and required Commission determinations on a fully developed record. This case is, to this general extent, a mirror image of the earlier case.

> proof, in support of the opposing party's preferred result. The presiding officer may allow discovery on the proposed settlement in the presiding officer's discretion.

WAC 480-07-740(2)(c).

62 All parties met their obligations under, and availed themselves of their rights as identified in, these rules.[47]

63 The Commission approves settlements when doing so is lawful, the settlement terms are supported by an appropriate record, and the result is consistent with the public interest in light of all the information available to the Commission. Ultimately, in settlements, as in fully-litigated rate cases, the Commission must determine that the resulting rates are fair, just, reasonable, and sufficient, as required by state law.[48]

64 In this case, all parties but one support or do not oppose the terms of the Settlement Stipulation with respect to all revenue requirements issues that are determinative of electric and natural gas rates. A significant number of restating and pro forma adjustments to test year results were uncontested by any party at the time set for

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[47] We note here Public Counsel's complaint in its Initial Brief that "[e]ven though the Settling Parties [sic] testimony regarding the cost of capital relies on the direct testimony of the Settling Parties' witnesses, Public Counsel was prohibited from questioning the witnesses *on that direct testimony*." Public Counsel Initial Brief ¶39 (emphasis added). Public Counsel was free to, and did, cross-examine the settlement witnesses with respect to their testimony supporting the 9.5 percent return on equity included in the Settlement Stipulation. TR. 592:21-594:223; TR. 600:17-601:24. As the cited colloquy shows, however, Public Counsel failed to take Ms. Barnard's point that as a settlement witness, not an expert witness on cost of capital, she could "only talk at a high level about the settlement and the 9.5 and why we believe it's reasonable." TR. 593:8-10. Public Counsel sought to cross-examine Ms. Barnard about PSE cost of capital expert witness Dr. Morin's testimony. TR. 592:21- 593:11. The presiding administrative law judge (ALJ) cut off this line of inquiry considering that it would be fundamentally improper to allow cross-examination of witnesses except with respect to their own testimony. Settlement witnesses cannot be cross-examined in a settlement hearing with respect to the testimony of other witnesses, such as cost of capital expert witnesses, just as they would not be allowed to be so cross-examined in a fully litigated case. The presiding ALJ explained that the Commission would consider all relevant information available to it, including the prefiled testimony of all cost of capital witnesses, when weighing whether the Settlement Stipulation proposed a reasonable resolution of this issue supported by the record, and would consider Public Counsel's "alternative view" of what would be a reasonable outcome. TR. 593:12 - 594:8.

[48] WAC 480-07-750(1). *See, e.g., WUTC v. Avista Corporation d/b/a Avista Utilities*, Dockets UE-150204 and UG-150205 (consolidated), Order 05 ¶¶20-22 (January 6, 2016).

evidentiary hearings. The Settling Parties agreed to specific results to other issues that remained contested as the hearing date approached.

65 Even Public Counsel, while contending it is generally opposed to the Settlement Stipulation,[49] stated its agreement to numerous discrete issues.[50] Indeed, Public Counsel identified in its Initial Brief only seven revenue requirements issues and three non-revenue requirements proposals by the Settling Parties to which it takes exception.[51] In contrast, Public Counsel acknowledged 28 revenue requirements issues as to which it either was "neutral" or "accepted" the Settling Parties' proposed resolutions. Public Counsel also agreed with the Settlement Stipulation's proposed resolution of Adjustments 11.20 and 13.20, Payment Processing Costs for natural gas and electric operations. Public Counsel elected not to address in its Initial Brief, and hence waived, any objection with respect to one additional revenue requirements issue.[52] In addition, as previously discussed, Public Counsel supported the Settlement Stipulation with respect to phased elimination of Schedule 40, Low-Income issues, Decoupling to the extent settled,[53] the use of Production Tax Credits (PTCs) and Treasury Grants to offset Colstrip costs (*i.e.,* otherwise unrecovered depreciation at Colstrip Units 1 through 4; decommissioning and remediation costs), and the non-revenue conditions concerning Colstrip (*i.e.,* reporting requirements, operational study, and workshop).

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[49] Colamonici, Exh. CAC-1T at 15:10-13.

[50] Colamonici, Exh. CAC-1T at 11:15-12:24.

[51] It may be that in Public Counsel's view there are eight contested issues, including what it refers to as "overall revenue requirement." The Company's overall revenue requirement, however, is not independently determined. It reflects the Commission's determination of many underlying issues, including those contested by Public Counsel, such as cost of capital, Colstrip depreciation, and five specific revenue requirement adjustments that Public Counsel contests: natural gas distribution plant future net salvage, pension expense, environmental remediation, plant held for future use, and storm amortization.

[52] Investor-Supplied Working Capital Adjustments (Adjustment 13.23 electric; Adjustment 11.23 natural gas).

[53] We note that the Settling Parties agree only to Staff's proposal to set the total Allowed Revenue for fixed production costs recovery per decoupled group at the level the Commission authorizes in this general rate proceeding. Settlement Stipulation ¶113. All other issues with respect to PSE's revenue decoupling mechanism, including the earnings sharing mechanism, are not affected by the Settlement and are expressly identified as being subject to litigation. Settlement Stipulation ¶114.

66 Specifically benefitting low-income customers, the Settlement Stipulation recommends:

- Increased HELP bill assistance funding.
- Continuation of existing low-income weatherization funding commitments, including a shareholder contribution.
- $2 million in increased low-income weatherization funding over current levels.[54]
- HELP eligibility improvements.
- Establishment of a PSE Low-Income Advisory Committee.
- Consultation agreements regarding program modifications.

These components reflect PSE's long-standing commitment to its bill assistance and weatherization programs for low-income customers. This is reflected in the fact that many of the low-income provisions included in the Settlement were proposed by PSE in its initial filing in the case.

67 In terms of cost of capital, one of the two key factors determining revenue requirements in this case, the Settling Parties agree to reduce the return on equity component in the Company's capital structure to 9.5 percent from 9.8 percent, which is the level in effect today. The settled return on equity matches the return on equity currently approved for Avista and Pacific Power. Public Counsel contends this is "an unreasonably high authorized return on equity."[55]

68 In terms of the second key revenue requirements issue, Colstrip depreciation, the Settling Parties agree to continue using straight-line depreciation to allow PSE to recover the undepreciated shareholder investment in Colstrip Units 1 & 2, adjusting the depreciation schedule to reflect the planned closure of these facilities by July 1, 2022. Ms. Colamonici testified that "Public Counsel agrees that depreciation should be accelerated for Units 1

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[54] Ms. Collins testified for The Energy Project that:

> This is a one-time commitment that is in place until June 30, 2019. This will benefit the programs by making additional resources available for installation of Department of Commerce approved cost-effective energy efficiency measures. The funding can be applied to project coordination, health and safety measures, and repairs necessary for the installation, adding to the flexibility and effectiveness of weatherization program delivery.

S. Collins, Exh. SMC-4T at 5:10-15.

[55] Colamonici, Exh. CAC-1T at 2:13.

and 2."[56] Indeed, Public Counsel does not dispute the proposed use of a depreciation schedule tied to the planned closure date for Colstrip Units 1 & 2. At the same time, however, she testified the "Settlement's proposed annual depreciation expense for Colstrip Units 1 and 2 is excessive."[57] She proposes that "surplus depreciation" tied to other production assets should be used to offset Colstrip depreciation.[58]

69 The decision to close Colstrip Units 1 & 2 well in advance of them being fully depreciated under current depreciation schedules that run to 2035, raised not only issues of depreciation expense, but also questions concerning the costs of decommissioning and remediation that will be incurred in the future. PSE proposed, and the parties agreed in their settlement, to "repurpose" current regulatory liabilities consisting of Treasury Grants received in connection with the relicensing of the Lower Baker River and Snoqualmie River hydroelectric facilities, and Production Tax Credits arising from several wind power projects, as sources of funds to cover depreciation and future decommissioning and remediation costs.

70 Public Counsel does not oppose this means of financing Colstrip decommissioning and remediation cost, but Ms. Colamonici stated that "Public Counsel has some concerns on whether PSE's PTCs will be monetized . . . to offset any unrecovered depreciation expense associated with Colstrip Units 1 and 2."[59] She testified in addition, however, that "Public Counsel believes the risk of monetization is appropriately placed on PSE."[60]

71 The Settling Parties also agreed that the depreciation schedule, and corresponding depreciation expense, for Colstrip Units 3 and 4 would be recalculated to run through December 31, 2027. This compares to the current depreciation schedules ending in 2044 and 2045, respectively. Ms. Colamonici testified, "Public Counsel believes that a depreciation schedule ending in 2035 is more suitable for Units 3 and 4; however, Public Counsel would accept a depreciation schedule ending in 2030 as a reasonable settlement outcome."[61]

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[56] We note that there is no proposal in this case to use accelerated depreciation for any Colstrip assets as that term is used in the accounting profession. The Settlement Stipulation proposes to continue the use of straight-line depreciation but over a shorter time period.

[57] Colamonici, Exh. CAC-1T at 2:18-19.

[58] Colamonici, Exh. CAC-1T at 4:3-11; 20-22.

[59] Colamonici, Exh. CAC-1T at 5:8-10.

[60] Colamonici, Exh. CAC-1T at 5:11-12.

[61] Colamonici, Exh. CAC-1T at 4:22-5:2.

72 In terms of disputed issues not addressed by the Settlement Stipulation, we must resolve exclusively on the basis of our evidentiary record important cost of service study, rate design, and tariff related issues. The continuation of decoupling and the form it should take, if continued, remains in dispute, except that the parties agreed to accept Staff's proposed treatment of fixed production costs. Electric rate spread and rate design remain in dispute except that the Settling Parties propose that we accept:

- Staff's proposal for demand charges for Schedules 46 and 49.
- Staff's proposal to discontinue Schedule 40 at the conclusion of PSE's next general rate case.
- Recalculation of the allowed revenue per customer for schedules other than Schedule 40 when Microsoft is removed from Schedule 40, recalculated consistent with the contingent allowed revenue calculations illustrated in Exh. JAP-43 for all customers who continue to be a part of PSE's electric rate decoupling mechanism at that time.
- Kroger's proposed changes to Schedule 25.
- The change in the allocation (*i.e.*, rate spread) of PSE's electric revenue deficiency for Schedules 7A, 10, 11, 12, 25, 26, 29, 31, 46, and 49 from 75 percent to 65 percent of the average rate increase.

73 PSE's proposed Electric Cost Recovery Mechanism (ECRM), modeled after its natural gas pipeline Cost Recovery Mechanism (CRM), remains in dispute. Only PSE supports this proposal.

74 Natural gas rate spread and rate design are not part of the Settling Parties' agreement. A variety of proposals require our decisions on these issues.

75 We address first below the uncontested adjustments. Second, we discuss the two key contested issues that are the subject of the parties' Settlement Stipulation: 1) cost of capital and, specifically, return on equity; and 2) Colstrip issues, including depreciation related to Colstrip Units 1 & 2, and Colstrip Units 3 & 4. Third, in terms of revenue requirements, we resolve issues addressed by the Settlement Stipulation but contested by Public Counsel. Fourth, we address four non-revenue issues addressed in the Settlement Stipulation including: the prudence of eight specific decisions mostly related to uncontested power costs; PSE's proposed expedited rate filing (ERF) process; the proposed treatment of the Company's water heater program; and service quality. The first of these is uncontested, but the Settling Parties request express determinations of prudence. Public Counsel contests the other three.

76 With respect to the issues that are the subjects of the Settlement Stipulation, whether or not contested, the Commission must reach one of three possible results:

- Accept the proposed settlement without condition.
- Accept the proposed settlement subject to one or more conditions.
- Reject the proposed settlement.[62]

77 Any conditions imposed must be supported by the record. Conditions may result from Public Counsel's advocacy opposing the Settlement Stipulation, in part, or may be determined independently by the Commission considering the broader record. Ultimately, to the extent we approve settlement terms, the Commission formally adopts them as its own resolution of the issues.

78 Finally, we turn to our resolution of the non-revenue issues that are not addressed by the Settlement Stipulation and remain fully contested, including most decoupling proposals, PSE's proposed ECRM, and some electric and all natural gas cost of service, rate spread, and rate design issues identified by the parties. We resolve these issues based on the full record.

IV. Revenue Requirements

A. Uncontested Adjustments

79 Thirty adjustments to electric revenue requirements and twenty-one adjustments to natural gas revenue requirements proposed by PSE and reflected in the parties' Settlement Stipulation are uncontested. These are depicted in Appendix A to this Order, including revenue requirements metrics. These adjustments are uncontested and adequately supported by the record. We find they should be approved without exception or condition.

80 An additional adjustment, Tax Benefit of Pro Forma Interests, is a pass-through adjustment determined using an uncontroversial approach familiar to all parties. No party contested the manner in which Adjustments 13.05 (electric) and 11.05 (natural gas) – Tax Benefit of Pro Forma Interest should be calculated, although parties differed in the results based on the rate base items included. Accounting for the rate base items included in the Settlement Stipulation, the Settling Parties agreed that this adjustment increases net

[62] WAC 480-07-750(2).

operating income for electric operations by $54,067,781 and increases net operating income for natural gas operations by $18,475,298.[63]

81 Public Counsel contests certain rate base items addressed by the Settlement Stipulation. It would be a relatively straightforward matter to adjust the Tax Benefit of Pro Forma Interest calculation to adjust for any changes in rate base that result from our decisions in this Order. However, because we accept none of Public Counsel's proposed adjustments to rate base, the adjustment amounts agreed by the Settling Parties are approved and adopted for purposes of this Order.

B. Key Contested Issues Addressed by Settlement Stipulation

82 Taking a high level view of this general rate case, we see two principal drivers of revenue requirements. The first is the cost of capital; specifically, the rate of return on equity. The second is the depreciation expense attributable to Colstrip Units 1 through 4. Colstrip raises non-revenue issues as well, including the proposed use of Treasury Grants and not yet monetized PTCs to pay for increased depreciation expenses and, later, decommissioning and remediation costs. The Settling Parties propose, in part, resolutions of these issues in their stipulation. Public Counsel opposes the Settling Parties' recommendations concerning cost of capital and Colstrip. Because cost of capital and Colstrip issues have special significance in the context of this proceeding, we discuss them first below.

1. Capital Structure and Cost of Capital

a. Settlement Stipulation

83 The Settling Parties agree to a capital structure for PSE that includes 48.5 percent equity and 51.5 percent debt, an authorized return on equity for PSE of 9.50 percent, and an authorized cost of debt for PSE of 5.81 percent. Application of these factors results in an overall authorized rate of return for PSE of 7.60 percent, as reflected in Table 3A below.

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[63]Settlement Stipulation ¶23 n3 (Adjustment No. 13.05 – Tax Benefit of Pro Forma Interest is equal to the product of (i) electric rate base of $5,166,534,272, multiplied by (ii) the weighted average cost of debt of 2.99 percent, multiplied by (ii) the federal tax rate of 35 percent.)

Table 3A
Proposed Cost of Capital

	Capital Structure	Cost	Weighted Cost
Debt	51.5%	5.81%	2.99%
Equity	48.5%	9.50%	4.61%
Overall Rate of Return	100.0%		7.60%

This compares to PSE's currently approved cost of capital, as shown below in Table 3B.

Table 3B
Authorized Cost of Capital

	Capital Structure	Cost	Weighted Cost
Debt	52.0%	5.96%	3.10%
Equity	48.0%	9.80%	4.70%
Overall Rate of Return	100.0%		7.80%

84 Both tables reflect a blended cost of debt, most of which is priced at the higher rates for long-term debt relative to short-term debt, which is less than 5 percent of total debt. Expressed in dollars of revenue requirement, the proposed 30 basis point reduction in return on equity (ROE) from the current rate amounts to approximately $37.5 million less for electric operations and $11.25 million less for natural gas operations.[64]

85 The primary issue in dispute at this juncture is whether the Settlement Stipulation proposes a reasonable level for PSE's ROE, at 9.5 percent, or should be rejected in favor of Public Counsel's alternative view that PSE's ROE should be reduced by 95 basis points to 8.85 percent.[65] We evaluate this issue with reference to the full record.[66] This

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[64] *See* Cheesman, Exh. MCC-1T at 24:4-5, Table 4.

[65] Viewed on a stand-alone basis, a 95 basis point reduction in ROE represents a $118.8 million reduction in revenue requirement for electric operations and a $35.6 million reduction in revenue requirement for natural gas operations.

[66] We note Public Counsel's support in its Initial Brief of this familiar approach to contested issues in the context of the Commission's consideration of a Settlement Stipulation. Public Counsel, with reference to WAC 480-07-740(2)(c), observes that:

> Non-settling parties, such as Public Counsel in this case, may offer evidence and argument in opposition, and opponents retain certain expressed rights, including cross examination and the right to present evidence. WAC 480-07-740(2)(c). As

includes the settlement testimony supporting and opposing the compromise reflected in the Settlement Stipulation and the prefiled testimony prepared by four highly credentialed expert witnesses who provided for our record their detailed analyses of what PSE's ROE should be going forward from this point in time.[67]

86 The expert witnesses do not dispute that determining an appropriate ROE presents challenges. They rely on familiar analytic tools such as discounted cash flow (DCF) models and capital asset pricing models (CAPM). They use a variety of data sources to populate these and other models to arrive at and support their respective ROE recommendations. The results of the analytic models they use to estimate ROE can vary significantly due to subjective judgments they make when selecting specific approaches to each model and when selecting the information to use as inputs to their models. This is illustrated, for example, by the fact that all four experts use a form of the DCF model, yet arrive at results that range from 8.65 percent ROE to 9.8 percent ROE. Similarly, all four experts relied on CAPM approaches, yet determined results that range from 6.75 percent to 9.8 percent. The results vary with the experts' selection of proxy groups and their reliance on different sources for growth rates, discount rates, and risk premiums. All of the expert witnesses' analytical results are portrayed in Table 4.

> a result, the Commission must resolve the issues in this case as contested matters on the basis of the record before it while determining whether it will accept, reject, or modify the multiparty settlement. [*In re Puget Sound Energy*, Dockets UE-121373, UE-121697 and UG-121705, and UE-130137 and UG-130138, Order 06 and 07, Order Rejecting Multiparty Settlement ¶ 17 (Jun. 25, 2013)].
>
> To do this, the Commission "weighs the evidence offered in support of the common positions advocated by the Settling Parties against the evidence opposing the results advocated by the Settling Parties, and the evidence offered by the non-settling parties in support of the alternative results that they advocate." [*Id.]* The Commission decides each contested issue on its merits considering the full record. [*Id.*]

Public Counsel Initial Brief ¶¶36-37 (including footnoted citations in original).

[67] Each witness included testimony and an exhibit summarizing their professional credentials. *See* Morin, Exh. RAM-1T at 1:5-3:9; Exh. RAM-2; Woolridge, Exh. JRW-1T at 1:2-9; Exh. JRW-2; Parcell, Exh. DCP-1T at 1:3-19; Exh. DCP-2; Gorman, Exh. MPG-1T at 1:1-9; Exh. MPG-2.

Table 4: Summary of Witness ROE Financial Modeling Results

	Morin[68]	Parcell[69]	Gorman[70]	Woolridge[71]
DCF:				
Value Line Growth	**9.8%**		**9.4%**	
Analysts Growth	**9.4%**		**9.4%**	
Traditional DCF		**8.85%**		
Electric Proxy Group				**8.65%**
Morin Proxy Group				**8.85%**
Gas Proxy Group				**8.9%**
CAPM:				
Traditional CAPM:	**9.3%**	**6.75%**	**8.6%**	
Empirical CAPM:	**9.8%**		**Reject Morin**	
Electric Proxy Group				**7.7%**
Morin Proxy Group				**7.7%**
Gas Proxy Group				**7.9%**
Risk Premium:				
Historical Electric	**10.5%**		**9.8%**	
Allowed ROE	**10.7%**		**9.3%**	
Comparable Earnings		**9.5%**		
ROE Recommendation	**9.80%**	**9.20%**	**9.10%**	**8.85%**[72]

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[68] Morin, Exh. RAM-1T at 55:14.

[69] Parcell, Exh. DCP-1T at 4:1. Mr. Parcell actually selected the midpoints of a range of modeling results based on analysis of two proxy groups used for comparison purposes. The ranges of his DCF, CAPM and CE analysis are 8.7-9.0 percent (8.85 percent mid-point), 6.5-7.0 percent (6.75 percent mid-point), and 9.0-10.0 percent (9.5 percent mid-point), respectively.

[70] Gorman, Exh. MPG-1T at 12:1. Unlike his customary approach in previous Washington proceedings to produce his own modeling results, Mr. Gorman presents his analysis as a series of adjustments to the modeling employed by the Company's witness, Dr. Morin

[71] Woolridge, Exh. JRW-1T at 53:18. It is worth noting that Mr. Woolridge relies primarily on his DCF analysis to estimate PSE's cost of equity. He also prepared a CAPM study but places less weight on it because it provides a less reliable indication of equity cost rates for public utilities.

[72] Woolridge, Exh. JRW-1T at 54:2-5.

b. Public Counsel

87 Public Counsel does not contest PSE's proposed capital structure. Dr. Woolridge testified for Public Counsel that he accepted the Company's proposed short-term and long-term debt cost rates of 3.06 percent and 5.73 percent and also used PSE's proposed adjustments to the short-term and long-term debt cost rate for commitment fees and amortization of term issuance costs and of reacquired debt.

88 Ms. Colamonici testified that Public Counsel believes the record in this case supports returns that are lower than the Settlement's proposed 9.50 percent ROE and 7.6 percent ROR.[73] She points to the fact that two other Settling Parties, Commission Staff and ICNU, filed evidence indicating significantly lower recommendations. She fails to mention that these parties no longer advocate, respectively, 9.2 percent ROE and 9.1 percent ROE; they now support the 9.5 percent ROE that is the Settling Parties' compromise position within the ranges of possible and reasonable returns indicated by the expert testimony. Ms. Colamonici testified that Public Counsel's alternative view is that ROE is more appropriately set at 8.85 percent with an ROR of 7.28 percent.[74] As Dr. Woolridge recognized in his settlement response testimony:

> The primary reason provided in Staff's joint testimony . . . for supporting the ROE of 9.50 percent is that this figure is within the ROE ranges of PSE witness Dr. Roger Morin, Staff witness Mr. David Parcell, and ICNU witness Mr. Michael Gorman.[75]

89 Thus, Staff and the other Settling Parties recognized that a 9.5 percent ROE is in the range of reasonable returns shown by the record. In contrast, Ms. Colamonici testified that PSE's ROE should be set at 8.85 percent with an ROR of 7.28 percent,[76] based exclusively on Dr. Woolridge's ROE analyses and testimony, ignoring completely the

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[73] Colamonici, Exh. CAC-1T at 3:9-10.

[74] Colamonici, Exh. CAC-1T at 3:14-16 (with reference to Woolridge, Exh. JRW-1T – JWR-16).

[75] Woolridge, Exh. JRW-18T at 2:14-17. Dr. Woolridge's testimony belies the argument in Public Counsel's Initial Brief that "the Settlement testimony offers no rationale for why they chose this figure." Public Counsel Initial Brief ¶41. We note, too, that during cross-examination of Staff witnesses Schooley and Cheesman, Public Counsel elicited testimony confirming that "the ROE is 9.5, within the range of Dr. Morin, PSE['s] witness, and Staff['s witness] Mr. Parcell." TR. 601:14-18.

[76] Colamonici, Exh. CAC-1T at 3:14-16 (with reference to Woolridge, Exh. JRW-1T through Exh. JWR-16).

higher ROE levels shown by similar analyses performed by the other three cost of capital expert witnesses in this case, Dr. Morin, Mr. Parcell, and Mr. Gorman.

Commission Determination

90 Public Counsel's "alternative view" fails to acknowledge that it is well established regulatory practice, and indeed the Commission's long-standing practice, to first identify within the range of *possible* returns shown by expert analyses a range of *reasonable returns* on equity considering all cost of capital testimony in the record. Then, the Commission weighs the analysts' results falling within that range and considers other evidence relevant to the selection of a specific point value within the range. The Commission's final determination of what is an acceptable return on equity recognizes fully the guiding principles of regulatory ratemaking that require us to reach end results that yield fair, just, reasonable and sufficient rates.[77]

91 The Commission benefits significantly from being informed by the different perspectives the expert witnesses take in making their subjective judgments, but must carefully balance their results to establish the end points of a zone of reasonableness within which the selection of a specific point value can be made for ROE considering the modeling and other factors in evidence. Public Counsel's alternative view that we should ignore the larger body of evidence in favor of deciding the issue of ROE based largely, if not exclusively, on Dr. Woolridge's testimony is inconsistent with what we believe to be sound regulatory practice.[78]

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[77] *See Fed. Power Comm'n v. Hope Nat. Gas Co., (Hope)* 320 U.S. 591, 64 S. Ct. 281, 88 L. Ed. 333 (1944); *Bluefield Waterworks & Imp. Co. v. Pub. Serv. Comm'n of W. Va.*, (*Bluefield*) 262 U.S. 679, 43 S. Ct. 675, 67 L. Ed. 1176 (1923).

[78] Reliance on a single cost of capital expert witness would ignore that these witnesses have testified in many cases during their careers and are known to routinely testify on behalf of one class of interests or another among the diverse interests that regularly are represented in the utility ratemaking process. As the Commission discussed in an earlier order, it is not a criticism to observe that:

> They unquestionably are selected by their clients, in part, on the basis of their tendency to occupy a reasonably predictable relative position concerning the range and point values they recommend for return on equity in any given case. This merely emphasizes the point that regulators, considering the subjective and judgment-based models on which these experts rely, face the challenge in every case of weighing diverse testimony and sometimes wide-ranging estimates of the cost of equity capital. We must weigh this evidence carefully, considering the context in which the case is being considered and also factors such as the general state of the economy, investment cycles in the industry, the principle of

92 Dr. Woolridge's analytical results contribute to our determinations, being indicative as they are of lower rates of return now prevalent in the industry relative to earlier periods. Dr. Woolridge's reported results for PSE, however, are markedly low relative to the other witnesses' results and relative to the measures he cites throughout his own testimony as being indicative of ROE trends in the industry.[79] Dr. Morin critiques Dr. Woolridge's recommended ROE of 8.85 percent as being "well outside the zone of reasonableness and outside the zone of currently allowed returns on equity authorized by state utility commissions in 2017, which averages 9.9 percent." He also points out that Dr. Woolridge's recommended ROE lies well below the zone of the allowed and expected returns on equity of his own proxy group of electric utilities, whose earned returns on equity are 9.3 percent (electric) and 9.4 percent (gas).[80] Similar criticisms might be leveled at Dr. Morin's risk premium results at 10.5 percent and 10.7 percent. These might be considered markedly high results relative to what the full body of evidence otherwise suggests. Indeed, Dr. Woolridge offers an extensive critique of Dr. Morin's risk premium analyses.[81]

93 The range of possible returns on equity shown by the expert witnesses' respective analyses is 6.75 percent to 10.7 percent, a spread of nearly 400 basis points. Such a spread suggests that the lower end results and the higher end results shown in Table 4 are outside of the zone of reasonable returns, which typically is determined to fall within a somewhat narrower range. This is suggested, too, by broader trends in the industry, reflected for example in the expected and earned returns on equity experienced by the

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> gradualism, and so forth. In the final analysis, we must exercise our own informed judgment to determine, in the public interest, what constitutes a reasonable range of returns and what point value to select within this range to determine a company's revenue requirements and, hence, its rates.

In the Matter of the Petition of Puget Sound Energy and NW Energy Coalition For an Order Authorizing PSE to Implement Electric and Natural Gas Decoupling Mechanisms and to Record Accounting Entries Associated with the Mechanisms, Dockets UE-121697 and UG-121705 (consolidated) (Decoupling) and *Washington Utilities and Transportation Commission v. Puget Sound Energy*, Dockets UE-130137 and UG-130138 (consolidated) (ERF), Order 15/14 ¶32 (June 29, 2015).

[79] *See, e.g.,* Woolridge, Exh. JRW-1T at 54:20-55:3 ("The authorized ROEs for electric utilities have declined from 10.01 percent in 2012, to 9.8 percent in 2013, to 9.76 percent in 2014, 9.58 percent in 2015, and 9.60 percent in 2016, according to Regulatory Research Associates. The authorized ROEs for gas distribution companies have declined from 9.94 percent in 2012, to 9.68 percent in 2013, to 9.78 percent in 2014, 9.60 percent in 2015, and 9.50 percent in 2016.").

[80] Woolridge, Exh. JRW-1T at 20:11-12, 21.

[81] Woolridge, Exh. JRW-1T at 66:10-75:3.

companies in Dr. Woolridge's proxy groups. The conservative approach favored by the Commission leads us to reject the analytical results reported in this case that fall below 9.0 percent or above 10.0 percent and to select a narrower range of reasonable returns focusing on the cluster of values in the range from 9.3 percent to 9.8 percent. Indeed, considering all of the expert witnesses' analytical results and industry trends during recent periods, we determine that the range of reasonable returns is from 9.3 percent to 9.8 percent. Giving equal weight to all of the expert's results that fall within this range we determine that the Settlement Stipulation's proposed ROE of 9.5 percent is reasonable and fully supported by the record.[82]

94 The Commission determines for these reasons that it should approve and adopt the Settlement Stipulations recommended ROE of 9.5 percent. Inasmuch as the balance of the capital structure and cost of capital results proposed by the Settlement Stipulation are not contested, we also determine that we should approve and adopt an overall rate of return of 7.60 for purposes of establishing revenue requirements and rates in this proceeding.[83]

2. Colstrip Costs: Depreciation Expense; Future Decommissioning and Remediation Expense

95 PSE owns a 50 percent interest in two, and a 25 percent interest in two other, coal-fired generation facilities located in Colstrip, Montana. The first two facilities, known as Colstrip Units 1 & 2, were placed into service in 1975 and 1976, respectively. The other two facilities, known as Colstrip Units 3 & 4, were placed in service in 1984 and 1986. These are large baseload plants. Colstrip Units 1 & 2 have a combined capacity of approximately 614 MW. Colstrip Units 3 & 4 have a combined capacity of approximately 1480 MW.

96 The genesis of the problems we face today with respect to the Colstrip units is found, in part, in a Commission decision in 2008 in PSE's 2007 general rate case in Docket UE-072300. The Company put into evidence a depreciation study indicating a probable retirement year of 2019 for Colstrip Units 1 & 2 based on a projected 44-year lifespan for Unit 1 and a projected 43-year lifespan for Unit 2.[84] Based on similar projected lifespans,

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[82] We note, too, that a 30 basis point reduction from PSE's currently effective 9.8 percent ROE appropriately reflects the principle of gradualism in adjusting rates. In contrast, to approve the 95 basis point reduction Public Counsel advocates would be antithetical to this important ratemaking principle.

[83] *See supra* ¶ 49, Table 3A.

[84] Hausman, Exh. EDH-1T at 8:8-14.

PSE's 2007 depreciation study used 2024 and 2025 end-of-life dates for Colstrip Units 3 & 4, respectively.

97 Ultimately, however, the Company joined a multi-party settlement in Docket UE-072300 that recommended a 60-year life for these assets, thereby extending the depreciation schedule for the recovery of remaining plant balances through 2035 for Units 1 & 2 and through 2044 and 2045 for Units 3 & 4. This resulted in the Company recovering less depreciation expense year by year going forward.[85] The Commission approved and adopted the proposed settlement, accepting these recommendations by Staff and Public Counsel to which PSE acceded during the negotiation process.[86]

98 The Commission's 2008 order merely acknowledged this feature of the parties' settlement in a single paragraph[87] and did not discuss that the recommendations by Staff and Public Counsel focused on comparisons to other coal plants and historical data. Mr. Hausman, testifying in this case for Sierra Club, related that the data presented in 2007 included, for example, testimony from Public Counsel's witness Mr. King presenting an analysis of coal-fired plant retirements going back to 1900.[88] Thus, it appears that neither the parties recommending a change in Colstrip depreciation nor the Commission considered in 2007 that the operating environment affecting these facilities began changing significantly during the later years of the 20th Century and since 2000. Particularly during the current era, growth in demand for electricity slowed with the advent of stringent appliance energy efficiency standards, and successful utility-run energy efficiency programs such as PSE's conservation initiatives. Environmental regulations have required existing coal-fired plants to reduce their emissions, often necessitating expensive equipment additions and upgrades. The development of specific renewable energy sources has been subsidized by the federal government including

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[85] Another accounting measurement of the impact from recognizing the extended depreciation can be made by calculating a theoretical depreciation reserve for these assets.[85] In the case of all four Colstrip units this would be accomplished by calculating depreciation from each plant's in-service date, if built, or acquisition date, if purchased, *as if* the newly established, longer depreciation schedule had been in place from the beginning. The result would be a theoretical reserve surplus indicating depreciation over recovery.

[86] *WUTC v. Puget Sound Energy, Inc*., Dockets UE-072300 and UG-072301 (*consolidated*), Order 12, ¶¶ 57, 102 (October 8, 2008).

[87] *Id.* ¶ 57.

[88] Hausman, Exh. EDH-1T at 9:1-2 (citing WUTC Docket No. UE-072300, Testimony of William H. Weinman, (Exh. EDH-4 p. 8 at 7); and Testimony of Charles W. King, (Exh. EDH-5 pp. 11-12)).

Production Tax Credits for wind projects, and Treasury Grants for hydroelectric facilities. At the same time, the costs of renewables has come down significantly, while the demand for renewable sourced energy has increased as a result of state Renewable Portfolio Standards and other state policies. Finally, the availability of natural gas has increased and the current and expected cost of gas has dropped to the point where it is often cost-preferable to coal as a generation fuel.

99 All of these factors have combined to create conditions in which many coal plants cannot compete economically and cannot justify increased investments in environmental control technologies or improved operational efficiencies. According to Sierra Club witness Dr. Hausman, more than 250 coal plants, or about 50 percent of all coal plants in the United States, have retired or committed to retire since 2010.[89] In this environment where "even larger, younger coal plants are struggling to survive the economic competition from cleaner, cheaper energy sources,"[90] plants such as Colstrip Units 1 & 2, which are more than 40 years old, and even Colstrip Units 3 & 4, which are more than 30 years old, are at, or at least approaching, the end of their useful lives. There is a new focus, too, on the costs of decommissioning these facilities and remediating environmental damage they have caused. Many older coal-fired power plants, including the Colstrip facilities, were built and approved for recovery in utility rates before planning for decommissioning and remediation costs was standard practice.

100 These facts significantly implicate rates in the case of regulated utilities such as PSE, which is entitled to recover both return of, and return on, its prudent investments in assets over their useful lives. If changed circumstances, particularly circumstances beyond the utility's ability to control, result in it being prudent for power production assets to be retired earlier than anticipated, then rate regulatory authorities such as the Commission face the potentially daunting task of balancing the interests of shareholders in recovering the full costs of their investments and ratepayers in bearing those costs without suffering undue rate increases. In addition, earlier than anticipated plant closures, particularly coal plant closures, may impose decommissioning and environmental remediation costs for which adequate plans have not been made. Such are the challenges we face in this case with respect to Colstrip Units 1 through 4.

101 On July 12, 2016, PSE, current Colstrip coal plant operator Talen Energy (Talen), Sierra Club, and Montana Environmental Information Center filed a consent decree in the

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[89] Hausman, Exh. EDH-1T at 12:7-9.

[90] Hausman, Exh. EDH-1T at 12:9-10.

United States District Court of Montana setting a closure date for Colstrip Units 1 & 2 of no later than July 1, 2022.[91] PSE and Talen may shut these units down at an earlier date.

102 Preparing for this general rate case, which the Company was required to file by mid-January 2017, PSE commissioned a full depreciation study related to Electric, Gas, and Common plant as of September 30, 2016. Specifically regarding Colstrip Units 1 & 2, the study moved the depreciable life up by 13 years from 2035 to the agreed retirement date and used straight-line depreciation to recover the remaining net book value by mid-2022.

103 Although there is today no definite plan to close Colstrip Units 3 & 4 by a specific date, environmental and financial concerns affecting the prospects for continued operation of these plants influenced PSE to take a cautious and conservative approach to depreciation of these assets as well. PSE proposed in its depreciation study to shorten the depreciable lives of Colstrip Units 3 & 4 by about 10 years, from 2044 and 2045, respectively, to 2035. PSE's study again used straight-line depreciation to recover the remaining book value by December 31, 2035.

104 PSE also proposed in its filing in this case to place Treasury Grants it received in connection with its Lower Baker River and Snoqualmie River hydroelectric facilities and its existing PTCs into a regulatory liability account to fund decommissioning and remediation costs of Colstrip Units 1 & 2. This reflected both PSE's recognition of the necessity of planning for these future costs and the fact that during the 2016 legislative session, the Washington legislature passed Engrossed Substitute Senate Bill 6248 (ESSB 6248) expressly allowing the Commission to authorize electric companies to utilize regulatory liabilities to create reserve accounts for the purpose of funding decommissioning and remediation costs for eligible coal units.

105 With this background, we turn our attention to the Settling Parties' proposals related to depreciation and decommissioning and remediation costs, and to Public Counsel's alternative viewpoint that focuses on depreciation.

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[91] McGuire, Exh. CRM-1T at 9:1-4.

a. Settlement Stipulation

i. Depreciation Study (Electric Adjustment 13.06)[92]

106 The Settling Parties, putting their various litigation positions aside, ultimately agreed to use the depreciation study provided by PSE witness, Mr. Spanos,[93] subject to modifications, particularly with respect to Colstrip Units 3 & 4. Based on the projected closure date of mid-2022, the Settlement Stipulation sets depreciation rates for Colstrip Units 1 & 2 at amounts that would yield annual depreciation expense of $18.5 million for the remaining operational lives of those units.[94] PSE will recover the remaining plant balances for these assets using monetized PTCs as they become available for placement in a separate account that is expressly "not established" under the ESSB 6248.[95] PSE, however, assumes the risk that it may be unable to monetize the PTCs to offset all, or some part of, the unrecovered plant balances for these assets; provided, however, that if Colstrip Units 1 & 2 close prior to the monetization of sufficient PTCs to offset unrecovered plant balances, PSE will hold the remaining unrecovered plant balances in rate base as a regulatory asset until the earlier of (i) the recovery of all plant balances for Colstrip Units 1 & 2 through monetized PTC offsets or, (ii) December 31, 2029.[96]

107 The Settling Parties agreed to a depreciation schedule for Colstrip Units 3 & 4 that assumes a remaining useful life of those units through December 31, 2027. This is eight years less than what PSE proposed in its original filing. Staff's settlement witnesses point out that "the 2027 date is not a retirement date, but simply reduces the depreciable life for Units 3 and 4 by eight years compared to Mr. Spanos' depreciation study."[97] December 31, 2027, reflects a compromise position considering competing proposals presented by PSE and several other parties. The Settlement Stipulation sets depreciation rates for Colstrip Units 3 & 4 at amounts that will yield annual depreciation expense of

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[92] The Settling Parties similarly agree to use Mr. Spanos's depreciation study for Adjustment No. 11.06 – Depreciation Study (Natural Gas). They further agree that this adjustment is uncontested for natural gas operations and (i) increases net operating income for natural gas operations by $13,174,098 and (ii) increases rate base for natural gas operations by $6,587,049. The adjustment, however, is contested by Public Counsel. We discuss this separately below.

[93] Exh. JJS-3r.

[94] Schooley/Cheesman, Exh. TES-4T at 7:21-22.

[95] Codified as RCW Chapter 80.84.

[96] Settlement Stipulation ¶25.

[97] Schooley/Cheesman, Exh. TES-4T at 8:16-18.

approximately $23.3 million for the remaining depreciable lives of those units.[98] The settlement again provides that monetized PTCs will be used to recover any remaining plant balances. In contrast to the settlement provisions concerning Units 1 & 2, the Settlement Stipulation does not address the eventuality of there not being sufficient monetized PTCs to cover fully the remaining plant balances.

108 Sierra Club settlement witness Mr. Howell, while acknowledging that the Settlement Stipulation does not set a closure date for Colstrip Units 3 & 4, testified that it "sets a clear path for PSE to pay down the undepreciated plant balances on a schedule that better recognizes the fact that the entire Colstrip coal plant is unlikely to operate past 2025."[99] Mr. Howell testified in some detail concerning Sierra Club's view that "current economic, environmental and political factors demonstrate that Colstrip Units 3 and 4 are unlikely to operate past December 31, 2024."[100] Mr. Howell testified that Sierra Club would prefer an earlier date, but 2027 "represents a reasonable compromise for purposes of settlement that is in the public interest."[101] Indeed, Mr. Howell testified that "setting the depreciation schedule for Colstrip Units 3 and 4 at December 31, 2027, is a critical step in planning for the retirement of those units."[102] He referred to Dr. Hausman's testimony that current economic, environmental, and political factors suggest that Colstrip Units 3 & 4 are unlikely to operate past December 31, 2024,"[103] and then discussed specific examples reflecting these factors.[104]

109 PSE's settlement witnesses testified that "the realignment of the depreciation life for Colstrip Units 3 and 4 to December 31, 2027, is a way to minimize any future intergenerational inequities that could occur should circumstances change that further shorten the life of any of the Colstrip units."[105] Thus, "the 2027 depreciation date helps to lessen the risk of repeating the situation that arose with Colstrip Units 1 and 2 in 2008,

[98] Joint Memorandum in Support of Multiparty Partial Settlement ¶ 13.

[99] Howell, Exh. DHH-1T at 4:8-10.

[100] Howell, Exh. DHH-1T at 6:17-18. *See also id.* at 6:19-9:10.

[101] Howell, Exh. DHH-1T at 4:11-12. *See also id.* at 5:1-8.

[102] Howell, Exh. DHH-1T at 6:15-16,

[103] Howell, Exh. DHH-1T at 6:16-18.

[104] Howell, Exh. DHH-1T at 6:19-9:7

[105] Exh. PSE-1JT at 6:20-7:3.

when the assets' depreciable lives were extended, resulting in an undepreciated plant balance for those units at the time of retirement."[106]

110 Staff settlement witnesses Schooley and Cheesman testified concerning the difficulty of projecting the lives of coal-fired production plant. Though they do not refer to it, this difficulty is clearly evidenced by the unintended consequences of the Commission's decision in PSE's 2007 general rate case with respect to the depreciable lives for Colstrip Units 1 & 2. Had the Commission accepted PSE's original depreciation study in that case we would not be facing today the significant financial consequences of a decision in 2008 that proved with the passage of time to be ill-advised. Instead, Colstrip Units 1 & 2 would have been fully depreciated by 2019, and Units 3 & 4 would have been fully depreciated by 2024 and 2025. Informed by this experience, the Settlement Stipulation reconciles with recent decisions to close Units 1 & 2, reflects a more focused view with respect to Colstrip Units 3 & 4, and reduces the potential risk of large unrecoverable plant balances and the likelihood of facing intergenerational inequities for Units 3 and 4.[107]

ii. Accounting for Depreciation, and Decommissioning and Remediation

111 Balancing PSE's interest in recovering all of the net plant amounts remaining on its books for the Colstrip units as of September 30, 2016, against the Settling Parties' common interest in protecting ratepayers from significant rate impacts and avoiding intergenerational inequities, the Settlement Stipulation establishes two new accounts. One account will be used to manage repurposed Treasury Grants to fund decommissioning and remediation costs that will follow in the wake of the closure of the Colstrip plants. PSE will place $95 million in hydro-related Treasury Grants into a retirement account established pursuant to RCW 80.04.350 to fund and recover prudently incurred decommissioning and remediation costs for Colstrip Units 1 & 2, consistent with Chapter 80.84 RCW. In joint testimony supporting the Settlement Stipulation, Ms. Barnard, Ms. Free, and Mr. Piliaris testified that "[t]he existing $95 million in hydro-related Treasury Grants addresses nearly all of the estimated decommissioning and remediation costs for Colstrip Units 1 and 2."[108]

112 As PTCs are monetized, PSE will place them in a second, more flexible account that the Settling Parties expressly agree will not be established pursuant to Chapter 80.84 RCW.

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[106] Exh. PSE-1JT at 7:6-12.

[107] *See* Schooley/Cheesman, Exh. TES-4T at 8:14-22.

[108] Exh. PSE-1JT at 5:13-14.

PSE will use the monetized PTCs in the second account with the following priorities: (i) to fund community transition planning funds of $5 million for the benefit of citizens in Colstrip, Montana; (ii) to recover unrecovered plant balances for Colstrip Units 1 through 4; and (iii) to fund and recover prudently incurred decommissioning and remediation costs for Colstrip Units 1 through 4. PSE's witnesses supporting the settlement stated that "[b]ased on the average of the monthly averages balances in 2016, the PTCs available are estimated at approximately $280 million."[109] In addition to applying remaining available monetized PTCs to fund decommissioning and remediation costs, PSE will also apply the $95 million in Treasury Grants that will be statutorily earmarked for this purpose.[110]

113 PSE's witnesses testified that from the Company's perspective a key rationale for taking these accounting measures to address depreciation is that it is a way to avoid intergenerational inequities. They discuss that:

> Customers received the benefit of lower depreciation rates for all four units of the Colstrip Generating Plant during the 2009 through 2017 period due to the extension of the assets depreciable life to 60 years, as proposed by Public Counsel and Commission Staff in the 2007 general rate case, and as ultimately agreed to by PSE in the settlement of that case. This contributed to the undepreciated plant balance for Colstrip Units 1 and 2 that we now face, with Colstrip Units 1 and 2 scheduled to close no later than 2022. The time period when the depreciable lives were extended closely aligns with the period that the PTCs were generated; however, due to ongoing net operating losses PSE has not been able to … utilize these PTCs on its tax return and customers have not yet received the benefit of these credits. The use of some of the monetized PTCs to address the undepreciated balance of Colstrip units is a reasonable approach, and it allows the credits earned over this time period to pay for the undepreciated plant balance that accrued over approximately the same time period. This use of PTCs, along with the realignment of the depreciation life for Colstrip Units 3 and 4 to December 31, 2027, is a way to minimize any future intergenerational inequities that could occur should circumstances change that further shorten the life of any of the Colstrip units.[111]

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[109] Exh. PSE-1JT at 5:17-19 (citing Marcelia, Exh. MRM-1T at 9:Table 1).

[110] Exh. PSE-1JT at 5:19-6:3.

[111] Exh. PSE-1JT at 6:4-7:3.

Staff's settlement witnesses testified that by using PTCs in this fashion "there is a better balance between today's generation of customers and the future generations."[112] In addition, "PSE will be largely made whole for Colstrip Units 1 and 2; and the tax credits mitigate potential rate impacts if the depreciation expense is insufficient to recover the entire plant balances."[113]

114 Ms. Gerlitz testified for NWEC/RNW/NRDC that aligning the accounting treatment for Colstrip Units 1 & 2 with the agreement to close of these units no later than 2022 "reduces intergenerational inequity by paying off balances that have been historically under-recovered from customers utilizing Production Tax Credits that have been earned over approximately the same time-period under which the plant balances were under-recovered."[114] In addition, she testified that shortening the depreciation schedule for Colstrip Units 3 & 4 to December 31, 2027, aligns with a more accurate estimate of the useful life of these units and "reduce[s] the chances of repeating the mistakes made with regard to the unrecovered plant balances of Colstrip Units 1 and 2."[115] Referring to Dr. Power's response testimony for NWEC/RNW/NRDC, Ms. Gerlitz testified that "PSE failed to recover decommissioning and remediation costs for Colstrip Units 1 and 2 during their 40+ year lifetime … leaving current rate payers on the hook for substantial [retirement] costs."[116] The Settlement Stipulation, in contrast, aligns the recovery of Colstrip costs with the use of the assets thus providing inter-generational equity for costs of remediation, decommissioning, and demolition.[117]

115 Ms. Gerlitz testified further that:

> The Settlement provides a plan to fund future decommissioning and remediation costs at Colstrip Units 1, 2, 3, and 4. Decommissioning and remediation costs are among those that should have been collected throughout the useful life of these units, but were not adequately collected. Establishing a plan to fund these future costs with Treasury Grants, pursuant to RCW 80.84.020(2), and Production Tax Credits that have been

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[112] Schooley/Cheesman, Exh. TES-4T at 8:11-12.

[113] Schooley/Cheesman, Exh. TES-4T at 8:8-11.

[114] Gerlitz, Exh. WMG-1T at 5:14-19.

[115] Gerlitz, Exh. WMG-1T at 6:1-4.

[116] Gerlitz, Exh. WMG-1T at 6:6-10.

[117] *Id.*

> earned but not yet collected will provide more equitable treatment to customers and ensure that the initial estimates of the costs of these important responsibilities are fully and adequately funded.[118]

116 With respect to Colstrip Units 3 & 4, the Company's settlement witnesses emphasize that PSE is not the sole owner and cannot unilaterally set a retirement date for the plants. The 2027 depreciation date to which the Settling Parties agree, however, "helps to lessen the risk of repeating the situation that arose with Colstrip Units 1 and 2 in 2008, when the assets' depreciable lives were extended, resulting in an undepreciated plant balance for those units at the time of retirement."[119] Staff agrees that the settlement "dramatically reduces the potential for unrecovered plant in Colstrip Units 3 and 4."[120]

117 Staff's settlement witnesses testified similarly that 2027 is not a retirement date for Colstrip Units 3 & 4, but by addressing the difficult task of projecting coal-related plant lifespans, "the Settlement reduces the potential risk of large, unrecoverable plant balances [thus] drastically [reducing] the likelihood of facing intergenerational inequities for Units 3 and 4."[121]

b. Public Counsel's Alternative Viewpoint

i. Electric Depreciation Study (Electric Adjustment 13.06)

118 Public Counsel agrees that depreciation should be accelerated for Colstrip Units 1 & 2 and does not challenge the adoption of a depreciation schedule tied to the specific circumstances facing these assets, including their planned retirement date no later than 2022.[122] Nor, despite Ms. Colamonici's testimony that the depreciation expense contemplated under the Settlement Stipulation is "excessive,"[123] does Public Counsel suggest that PSE should be denied recovery of any part of its return of, or on, investment in these facilities. Instead, Public Counsel's witness Ms. McCullar advances an alternative approach to determining an effective depreciation schedule for recovery of the net book value of Colstrip Units 1 & 2. Ms. McCullar's proposal is based on theoretical

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[118] Gerlitz, Exh. WMG-1T at 6:11-17.

[119] Exh. PSE-1JT at 7:9-12.

[120] Schooley/Cheesman, Exh. TES-4T at 8:18-20.

[121] Schooley/Cheesman, Exh. TES-4T at 8:21-22. *See also* Howell, Exh. DHH-1T at 9:11-11:12.

[122] Public Counsel Initial Brief ¶ 54.

[123] Colamonici, Exh. CAC-1T at 2:18-19;

reserve calculations that are tied not to the retirement date for these assets, but rather to the reserve balances and wide ranging depreciation schedules of Colstrip and all other steam production plant included by PSE for accounting purposes in the same FERC functional classification accounts, Steam Production Accounts 311-316.[124]

119 Taking this expansive view, Ms. McCullar identified certain plants that have a theoretical reserve deficiency and others that have a theoretical reserve surplus.[125] Specifically, she testified that Colstrip Units 1 & 2 have a theoretical reserve deficiency of approximately $44 million, while the Goldendale plant alone has a theoretical reserve surplus of approximately $44 million.[126] PSE's overall Steam Production Plant, she testified, carries a surplus reserve balance even though there is a significant deficiency for Colstrip Units 1 & 2.[127] Despite having identified an example of a reserve surplus for Goldendale that more or less perfectly offsets the reserve deficiency attributable to Colstrip Units 1 & 2 in gross dollars, she identified the shortened remaining life of Colstrip Units 1 & 2 as a major reason for the overall reserve deficiency in these accounts.[128]

120 Public Counsel, through Ms. McCullar's testimony, proposes to reallocate the reserve surplus indicated for some steam production assets to offset the reserve deficiency attributable to Colstrip Units 1 & 2. In addition, Public Counsel contends "it is reasonable to use remaining life depreciation rates to address the reserve imbalances."[129] Thus, in effect, under Public Counsel's proposal, depreciation expenses for Colstrip Units 1 & 2 would be recovered not during the remaining life of the Colstrip assets, but rather over a range of remaining lives ranging from 5.6 years to 25.9 years.[130] This assumes, however,

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[124] Account 311 – *Structures and Improvements*, Account 312 – *Boiler Plant Equipment*, Account 314 – *Turbogenerator Units*, Account 315 – *Accessory Electric Equipment*, and Account 316 – *Miscellaneous Power Plant Equipment*.

[125] A reserve surplus indicates that there is more in the actual book reserve than is calculated to be needed based on the current depreciation study, and lowers the depreciation rate over the remaining life of the asset. A reserve deficiency indicates that there is not enough actual book reserve than is calculated to be needed based on the current depreciation study and would be recovered through higher depreciation rates over the remaining life of the asset. McCullar, Exh. RMM-1T at 8:13-20.

[126] McCullar, Exh. RMM-1T at 9:16-19.

[127] McCullar, Exh. RMM-1T at 8:8-11.

[128] McCullar, Exh. RMM-1T at 9:10-11. Goldendale depreciation, in contrast, currently is on a schedule with a remaining life of nearly 26 years.

[129] Public Counsel Initial Brief ¶ 55.

[130] *See* McCullar, Exh. RMM-1T at 12:1 Table 4.

that the remaining lives of all plant remains unchanged from this time forward, an assumption already undercut in the case of Colstrip Units 3 & 4 that are shown by Ms. McCullar to have remaining lives of 11.6 years through 2035, which is eight years longer than what is proposed under the Settlement Stipulation. It is entirely possible, too, that there will be a need to adjust the depreciation schedules for other steam production plant in future years. This raises uncertainties concerning whether reallocating depreciation reserves as Public Counsel proposes might lead to unintended consequences just as the 2007 adjustment to Colstrip depreciation led to the problems we address here. Public Counsel does not consider this possibility.

121 Ms. McCullar's proposal, in essence, is to establish a cross-subsidization among the individual plant balances to apply surplus monies from some plants within the Steam Production Accounts functional classification to offset the deficiencies of other plants.[131] This reallocation results in an overall decrease to the depreciation rates proposed by PSE and, consequently, a reduction in the depreciation accrual.

122 Mr. Spanos testified for PSE in rebuttal that Public Counsel's proposal would result in future customers paying the costs of Colstrip Units 1 & 2 after the facility is retired. This would, by definition, "result in intergenerational inequity, as future customers will be forced to pay the costs of a facility from which they receive no service."[132] Mr. Spanos testified specifically that Ms. McCullar's proposal that a portion of the Colstrip Units 1 & 2 book reserve be transferred to other steam production plants, including PSE's combined cycle facilities, would result in Colstrip Units 1 & 2 costs being recovered over the remaining lives of the other plants in steam production. Thus, he said, "customers would still be paying for Colstrip Units 1 and 2 for 25 years after the plants are retired."[133]

123 Mr. Spanos also identified and discussed calculation issues in Public Counsel's proposal due to Ms. McCullar's failure to account properly for the age of many of PSE's facilities. This is important, he testified, because a theoretical reserve calculation such as that on which Ms. McCullar relies, is a function of the estimated life and net salvage estimates, as well as the vintages of plant in service in the calculation.[134] According to Mr. Spanos,

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[131] McCullar, Exh. RMM-1T at 12:9-13:2.

[132] Spanos, Exh. JJS-4T at 9:2-7.

[133] Spanos, Exh. JJS-4T at 12:18-23.

[134] Spanos, Exh. JJS-4T at 16:15-19. By way of background, Mr. Spanos testified that "net salvage as used in depreciation is defined as gross salvage less cost of removal." Put another way, net salvage is gross salvage (*i.e.,* scrap or reuse value) less the costs to retire the asset. Mr. Spanos testified that like "[m]ost types of utility property" PSE's assets "typically experience negative

Ms. McCullar failed to recognize that with respect to many of the combined cycle plants the vintages recorded on PSE's books are the dates the plants were acquired, not the dates when they were placed into service. By way of examples, he testified that the three plants Ms. McCullar identifies as having the largest reserve imbalances, Goldendale, Sumas, and Ferndale, were placed in service in 2004, 1993, and 1994, respectively. Ms. McCullar, using the acquisition dates of 2007, 2008, and 2012 as the vintage dates for her theoretical reserve calculation, understated the actual reserve balances for these plants by close to $20 million.[135]

124 Mr. Spanos testified for PSE that Ms. McCullar's proposal defers costs to future customers and "will not result in the full recovery of the costs associated with PSE's power plants through straight line depreciation rates."[136] Thus, her proposal would increase the risk of a recurrence of situations such as the one currently facing PSE and its customers with respect to Colstrip Units 1 & 2, where a high level of unrecovered costs must be recovered over a relatively short period of time.[137]

125 Raising another issue that affects depreciation rates, Ms. McCullar testified that PSE inflated the estimated terminal net salvage costs of Colstrip Units 1 & 2 through the end of their lives, but proposes to recover the future inflated estimated salvage costs in today's more valuable dollars.[138] She recommended collecting the estimated net salvage costs in 2018-dollars.

126 Similarly, Ms. McCullar stated that PSE calculated Colstrip Units 3 & 4 terminal net salvage costs in 2016-dollars and then assumed an annual 2.5 percent inflation rate to

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net salvage, meaning that cost of removal exceeds gross salvage." Net salvage is expressed as a percentage of the original cost retired estimated using a combination of statistical analysis of historical data and applying informed judgment that incorporates other factors. Spanos, Exh. JJS-4T at 19:1-6 (internal citations omitted).

[135] Spanos, Exh. JJS-4T at 16:22-17:13.

[136] Spanos, Exh. JJS-4T at 31:16-19.

[137] Spanos, Exh. JJS-4T at 31:19-22.

[138] McCullar, Exh. RMM-1T 14:22-15:4. Terminal net salvage costs are costs associated with the closure of a production plant. Net salvage is defined as the gross salvage for the property retired less its cost of removal. Gross salvage is the amount recorded for the property retired due to the sale, reimbursement, or reuse of the property. Cost of removal is the cost incurred in connection with the retirement from service and the disposition of depreciable plant. Cost of removal may be incurred for plant that is retired in place. NARUC, *Public Utilities Depreciation Practices* at Glossary.

2035-dollars.[139] PSE then used the 2035-dollars to calculate the amount to be collected in 2018. This is unfair, Ms. McCullar argued, because 2035-year dollars will have a lower purchasing power than 2018-year dollars. Thus, she said, PSE essentially assumed 2035-dollars will be worth only $0.63 compared to 2016-year dollars.[140] The problem, she testified, is determining the quantity of dollars in the lower value year 2035-dollars and collecting that quantity in the more valuable current dollars. She described this approach as being unreasonable and unfair to ratepayers.

127 With respect to terminal net salvage, Mr. Spanos stated that if PSE is to recover the service value of its assets, "net salvage must be determined at the cost that will be incurred in the future."[141] Furthermore "[u]nder the straight line method of depreciation, these costs are recovered ratably, or in equal amounts each year, over the life of PSE's power plant."[142] The costs of removal thus must be recovered through depreciation during the life of the plant as part of net salvage, but those costs will occur in the future. It follows, according to Mr. Spanos that "it is the future costs that must be included in depreciation rates."[143]

128 Ms. McCullar also challenges the Settling Parties' treatment of net salvage for mass assets such as electric poles and wires. She contends that future net salvage estimates should depend on historical net salvage actually measured over five years.

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[139] This testimony was tied to PSE's original proposal in this proceeding for a depreciation schedule for Colstrip Units 3 & 4 that would end in 2035. Ms. McCullar filed settlement testimony for Public Counsel but did not update her analysis to reflect the different depreciation schedule recommended by the Settling Parties. We nevertheless can address the principles upon which her testimony rests.

[140] McCullar, Exh. RMM-1T at 15:9–16:11. As an example, Ms. McCullar asks the reader to assume a widget costs $36,000 today. With 2.5 percent inflation, PSE assumes that widget would cost $58,000 in 2035 dollars. She argues it is not reasonable to charge someone $58,000 in today's dollars to buy something that only costs $36,000 just because PSE claims it will cost $58,000 in 19 years.

[141] Spanos, Exh. JJS-4T at 32:1-3.

[142] Spanos, Exh. JJS-4T at 32:3-5. Mr. Spanos later testified that:

> [T]he vast majority of jurisdictions use a method for net salvage in which future net salvage is estimated at its future cost and recovered through straight-line depreciation. To my knowledge, the method of recovering future costs using straight line depreciation is used by 46 of the 50 states as well as by FERC.

Id. at 35:4-8.

[143] Spanos, Exh. JJS-4T at 33:2-3.

129 This is, according to PSE witness Mr. Spanos, an issue related to, but distinct from, the terminal net salvage issues Public Counsel raises with respect to Colstrip. According to Mr. Spanos, both proposals reduce the amount of net salvage in depreciation rates and defer these costs to future customers.[144] With respect to net salvage for mass property, Mr. Spanos testified that Ms. McCullar's proposal for Public Counsel is not based on accepted depreciation practice and appears to be designed to arbitrarily reduce depreciation expense and defer costs to future customers who would be required to pay for assets that no longer provide service.[145]

130 Finally, Ms. Colamonici asserted for Public Counsel that the record does not provide the necessary evidence for the Settlement Stipulation's recommended depreciation date of 2027 for Units 3 & 4, but testified that Public Counsel would accept a depreciation schedule ending in 2030 as a reasonable settlement outcome."[146] Ms. McCullar testified that PSE's original proposal in this case, a 2035 retirement year, "is reasonable for calculating depreciation rates."[147] However, in apparent contradiction to her support for a 2035 date, she further testified that "a 2030 retirement year seems more reasonable for settlement purposes given the 2025 to 2035 range in the proceeding."[148]

Commission Determinations

131 The Settling Parties' proposal is straightforward and transparent. It takes into account the fact that shortening the depreciation schedules for PSE's share of the four Colstrip plants means that the large net book balances that have not yet been recovered by PSE through depreciation expense in rates must now be recovered over a much shorter period of time.

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[144] Spanos, Exh. JJS-4T at 17:10-20.

[145] We discuss net salvage for mass assets in more detail below in connection with Adjustment 11.06 for Natural Gas. *See infra* ¶¶ 156-66. The same points discussed there are equally relevant here.

[146] Colamonici, Exh. CAC-1T at 4:22-5:2. We note here the perfect symmetry between Sierra Club's preference for a depreciation schedule through 2024 for Colstrip Units 3 & 4, Public Counsel's willingness to accept a depreciation schedule through 2030, and the Settlement Stipulation that provides for a depreciation schedule that ends in 2027.

[147] McCullar, Exh. RMM-12T at 7:7-8.

[148] McCullar, Exh. RMM-12T at 8:1-2. As previously discussed, the range in the underlying testimony actually is from 2024 (Sierra Club) to 2035 (PSE) and the range identified in the settlement testimony, including Mr. Howell's testimony for Sierra Club, and Ms. McCullar's and Ms. Colamonici's testimony for Public Counsel concerning these parties' preferred settlement outcome, is 2024 to 2030. This being true, the Settling Parties' selection of a 2027 date appears to be a reasonable compromise.

The Settling Parties' agreement adheres to the requirements of the familiar straight-line methodology for depreciation of assets that the Company has been authorized to use for all of its steam generation plants over many years. This approach results in a significant, even dramatic, increase in the recovery of depreciation expense in rates over the shortened remaining lives of the Colstrip assets relative to what has been recovered annually since 2008. Considering several fundamentally important principles of utility rate regulation, this confronts us with an intractable, but not impossible problem: How can the Commission best maintain reasonable stability in rates, protect ratepayers from rate shock, and avoid intergenerational inequities by shifting these costs into periods beyond the time the assets are no longer used and useful, while at the same time protecting the right of PSE's shareholders to full and timely recovery of the costs of their investments in Colstrip?[149]

132 The Settling Parties answer this question by proposing to use monetized PTCs to offset fully the remaining depreciation balances over the remaining lives of the Colstrip facilities. It appears these funds will be adequate to accomplish this offset with respect to Colstrip Units 1 & 2, but recognizing that this might turn out for one reason or another not to be the case, PSE assumes the risk in the manner previously described. It also appears that the PTC balances, if fully monetized, will be adequate to offset any unrecovered Colstrip Units 3 & 4 depreciation. The Settling Parties, however, agree it is premature to consider any allocation of risk if this turns out not to be the case at some point in the future.

133 Public Counsel's alternative viewpoint on recovery, in contrast to that of the Settling Parties, was presented through Ms. McCullar's testimony in a proposal that is neither straightforward nor entirely clear. In general, Public Counsel's proposal depends on flawed theoretical depreciation reserve calculations[150] and cost shifting effecting a cross-subsidization of depreciation expense recovery among all of PSE's steam production plants. Public Counsel's proposal also includes temporal shifts in depreciation cost

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[149] We recognize the shareholders also have a right to recover a return on their investments but there seems to be at least tacit agreement among all parties that the *return on investment* impact of whatever solution we adopt will simply follow from our determination of a plan for the *return of investment* to PSE.

[150] Theoretical reserve calculations are performed a function of the estimated life and net salvage estimates, as well as the vintages of plant in service in the calculation. These calculations may be useful tools in depreciation studies, allowing, as they do, consideration of alternatives when evaluating what might be an appropriate schedule to maintain or to change going forward. Ms. McCullar, however, does not refer us to any example in practice, or identify any professional literature, that supports using theoretical depreciation reserve calculations as she proposes in this case.

recovery so that significant depreciation expense attributable to the Colstrip units would not be recovered during the remaining useful lives of Units 1 & 2 that is pegged to the planned closure of those facilities, or the projected remaining useful life of Units 3 & 4 that we approve in this Order. Instead, Colstrip depreciation costs would effectively be recovered over periods that extend forward by as much as 25.9 years. This feature alone undercuts two of the Commission's goals: avoiding intergenerational cost shifting and allowing PSE to recover timely the remaining net balances on PSE's books today considering the significantly shortened depreciation schedules of the Colstrip assets.

134 Public Counsel's proposal also fails to make clear the bases for reallocating depreciation expense among PSE's 10 steam production plants. Ms. McCullar does not explain her methodology, so we cannot evaluate whether it has some principled basis or is simply arbitrary. With no explanation, Ms. McCullar would not limit the reallocation of theoretical depreciation reserve surpluses to offset increased Colstrip depreciation. She also reallocates some part of the theoretical depreciation reserve surpluses to other plant for which her analysis indicates theoretical depreciation reserve deficiencies. Yet, she offers no details concerning what specific surpluses she proposes to offset what specific deficiencies. This leaves us in the dark concerning the question of over what periods PSE could expect to recover its full investment in every plant in the Company's steam production plant portfolio.

135 It also appears that Public Counsel's proposal reflects flaws in both Ms. McCullar's method and her calculations of actual depreciation expense, net salvage, and theoretical depreciation reserves.[151] While Public Counsel suggests in its Initial Brief that we need not be concerned with a $20 million error in Ms. McCullar's determination of theoretical reserve balances,[152] an apparent error of this magnitude undermines the credibility of her entire analysis. Finally, Public Counsel offers no response through its brief to Mr. Spanos' testimony that Ms. McCullar's approach to determining net salvage is not supported by the accounting literature.

136 In the final analysis, we determine that the Settlement Stipulation takes advantage of the unique circumstances[153] in which PSE, without significant rate impacts, is able to recover

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[151] *See supra ¶ 129.*

[152] Public Counsel Initial Brief ¶56.

[153] We note that other Washington utilities with an ownership interest in the Colstrip plant may not have the same financial tools available to them as PSE did in this case to mitigate rate impacts from any proposed change to their current depreciation schedule or to pay for decommissioning and remediation costs for Colstrip Units 3 & 4. For these utilities, the Commission will need to

fully the undepreciated Colstrip plant balances on the Company's books on significantly shortened depreciation schedules tied to the known retirement date for Units 1 & 2 and a well-considered change for Units 3 & 4. The Settling Parties also have found the means to provide funding for future decommissioning and remediation costs that will be incurred in connection with the closure of all Colstrip facilities. Finally, the Settling Parties have identified existing funds to match shareholder funds that PSE commits to use in assisting the Colstrip community's transition to a new future. We find the use of Treasury Grant funds, repurposed as allowed by the Washington legislature, and monetized Production Tax Credits to fund these purposes provides direct benefits to PSE's ratepayers commensurate with the amounts PSE expects to expend.

137 Public Counsel's alternative viewpoint seems to present an unnecessary and unjustified complication to the Settling Parties' proposals most of which Public Counsel either supports or, at least, does not meaningfully oppose. Moreover, we find Public Counsel's proposed cost shifting, while giving the appearance of reducing customer impacts, actually does no more than shift costs to future generation of customers who would be required to pay for plant that is no longer used and useful.

138 In the final analysis, we determine that the Commission should approve and adopt the Settlement Stipulation's proposed resolutions of the issues related to Colstrip, as discussed above. The results are lawful, supported by the record, in the public interest, and reasonable.

ii. **Other Colstrip Issues**

139 As previously discussed, the remaining Colstrip issues are uncontested. Public Counsel supports the use of PTCs and Treasury Grants to pay otherwise under-recovered depreciation expense, as well as decommissioning and remediation costs. Public Counsel supports the proposal for Colstrip community transition planning and funding, despite having "some concerns" with prioritization of the use of PTCs for this undertaking. Public Counsel also supports the Settlement Stipulation's Colstrip provisions that establish reporting requirements, provide for a transmission system operational study, and provide for a transmission system workshop. We discuss below two somewhat nuanced arguments from Public Counsel on these issues.

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carefully consider the rate impacts of changing depreciation schedules or setting aside funds for decommissioning and remediation costs against the evidentiary record in those proceedings and parties' arguments for consistency with today's decision.

140 Public Counsel acknowledges that the balance of Production Tax Credits on PSE's books that the Settlement Stipulation proposes to use to fund Colstrip expenses that will be incurred in the future appears to be adequate to meet the anticipated costs of all proposed uses. However, Public Counsel states it "has some concerns about the prioritization given to the various uses."[154]

141 Ms. Colamonici acknowledged that community transition and planning is a key issue for the community of Colstrip, Montana, but testified that this obligation, insofar as PSE is implicated, is primarily a shareholder obligation, not an obligation of PSE's ratepayers.[155] Public Counsel believes the first priority for monetized PTCs should be to benefit ratepayers and recommends the following order of priority:

- Pay prudently incurred decommissioning and remediation costs for Colstrip Units 1 through 4.
- Offset unrecovered plant balances for Colstrip Units 1 through 4.
  Provide community transition planning funds of $5 million.

142 Ms. Colamonici would place the risk of monetization fully on the Company and, if the balance of monetized PTCs proves ultimately to be insufficient to cover all three categories of costs, "PSE's shareholders should reimburse the $5 million in PTCs so those funds can be used to either offset plant balances or pay for cleanup costs."[156] Ms. Colamonici notes that as a practical matter "the transition planning will occur first in time. Thus, PSE would likely be in a scenario of reimbursing the funds so that future cleanup costs can be paid or unrecovered plant can be offset."[157]

143 Finally, Public Counsel supports PSE's assumption of risk under the terms of the Settlement Stipulation with respect to the adequacy of monetized PTCs to cover costs at Colstrip Units 1 & 2.[158] Public Counsel recommends that we require PSE to accept the same assumption of risk with respect to possible use of such funds to offset unrecovered plant costs for Colstrip Units 3 & 4.[159] PSE argues this would not be reasonable

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[154] Public Counsel Initial Brief ¶63.

[155] Colamonici, Exh. CAC-1T at 13:19-22.

[156] Colamonici, Exh. CAC-1T at 14:10-18.

[157] Colamonici, Exh. CAC-1T at 14, n47.

[158] Settlement Stipulation ¶25.

[159] Public Counsel Initial Brief ¶64.

considering its status as a minority owner with no ability to control decisions concerning the timing of plant closure at Units 3 & 4.

Commission Determination

144 It appears that while Public Counsel discusses its concerns regarding the priorities established by the Settlement Stipulation for the use of monetized PTCs, Public Counsel does not advocate that we condition our approval of the settlement in this regard. In contrast, Public Counsel recommends that we require PSE to accept the same assumption of risk with respect to possible use of such funds to offset unrecovered plant costs for Colstrip Units 3 & 4.

145 We find it unnecessary at this point in time to impose a condition with respect to either of these concerns. The potential for actual problems in these regards is remote, considering the expected time-frame during which PSE should be able to monetize PTCs in amounts sufficient to cover all of the proposed costs they are targeted to cover and that Colstrip Units 3 & 4 are not on a definite schedule for closure. We determine that the Commission should approve and adopt the Settlement Stipulation's proposed resolution of these issues.

C. Contested Revenue Requirement Adjustments

1. Overall Revenue Requirement

146 By way of introduction to its arguments concerning revenue requirements, other than the cost of capital impact that Public Counsel discusses separately below, Public Counsel presents an argument in its Initial Brief concerning the Settlement Stipulation's "overall annual increase to electric revenues of $20 million" and "decrease to natural gas revenues of $35 million." Public Counsel compares these overall revenue adjustments to the parties' respective litigation positions.[160] Although not entirely clear on this point, it appears that Public Counsel would have us accept these litigation positions, as "potential reasonable outcomes in the case."[161] Acknowledging the extreme range of results the parties advocate, from a $63.3 million revenue requirement increase advocated by PSE to a $34.6 million revenue requirement decrease advocated by Staff for electric operations, Public Counsel nonetheless infers that a $20 million increase "is too generous and not in the public interest." Public Counsel says in addition that "the overall revenue provided

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[160] Public Counsel Initial Brief ¶¶44-46.

[161] Public Counsel Initial Brief ¶44.

under the settlement exceeds what PSE needs to reasonably and fairly run its utility business."[162]

147 As in the case of its arguments concerning cost of capital, Public Counsel ignores that, in every general rate case, the Commission is presented with a range of results, some of which will ultimately be found reasonable and some of which will not. Almost without exception, in the final analysis the Commission will determine revenue requirements and rates that fall somewhere within the range of *possible* outcomes as to which evidence was presented. The Settlement Stipulation reflects such results and clearly is the product of compromise resulting in PSE recovering a lower revenue requirement for electric operations, as advocated by the other parties, and greater revenue requirement reductions for natural gas operations, again as advocated by the other parties.

148 Accepting for the purpose of discussion that we can view each party's litigation position as a "potential reasonable outcome," we reject Public Counsel's inferences. We consider, for example, that to reach the settlement result, PSE had to accept $48.3 million less than the amount it advocated. Relative to Public Counsel's litigation position, the $20 million compromise in the settlement represents an increase of $35.9 million. Ignoring the host of other considerations involved in determining revenue requirements, the Settlement Stipulation strikes a reasonable compromise that is much in Public Counsel's favor. Viewed in this context, Public Counsel's inferences do not hold up.

149 If, then, we give any credence to the comparison Public Counsel draws, it demonstrates not that the Settlement Stipulation is "too generous and not in the public interest" but, to the contrary, shows it to represent outcomes we can measure against the fair, just, reasonable, and sufficient standard that governs our determinations. The revenue requirements the parties negotiated in the Settlement Stipulation do not reflect a "black box" agreement, *i.e.,* numbers with little or no explanation of how they were derived, but are based upon specific agreements on discrete adjustments, discussed further below, to reach the final revenue requirement. We consider, too, the Settling Parties' testimonies in support of their compromise on revenue requirements.

150 Mr. Mullins testified for ICNU that with respect to electric service, the Settlement Stipulation yields "yield[s] a fair and reasonable result for ICNU's members who take service from [PSE because] it reduces the Company's requested rate increase from net

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[162] *Id.*

3.2% overall in its supplemental filing to 0.9%."[163] With respect to gas services, Mr. Mullins testified that "[t]he settlement will result in a net revenue requirement decrease of approximately (-)3.8% for gas services, compared to rates customers are paying today," while "the Company's supplemental filing requested a decrease of only (-)3.2%, compared to today's rates."[164] This represents about $5 million in savings to gas customers, and NWIGU is supportive of the reasonableness of that result.[165]

151 Mr. Al-Jabir testified for FEA that the Settlement Stipulation is acceptable because it reduces the overall net electric revenue requirement increase from approximately $68 million (3.2 percent) under PSE's supplemental filing in this proceeding to approximately $20 million (0.9 percent) under the Settlement.[166] Kroger, too, agrees that "the overall electric revenue requirement negotiated by the parties to the Settlement produces a just and reasonable result that is in the public interest."[167]

152 Reflecting on the parties' joint efforts in their settlement testimony, Mr. Schooley and Ms. Cheesman testified that:

> Staff's recommendation [that the Commission adopt the settlement without condition] is the result of four rounds of testimony, several months of discovery, and a series of complex, and at times contentious negotiations, settlement discussions with interested parties, representing stakeholders with very different interests. The Settling Parties' proposed Settlement brings 10 of those stakeholders together and provides a fair and reasonable resolution to the settled issues in this case.
>
> As part of its decision to join the Settlement, Staff considered the range of potential outcomes of further litigation (or litigation risk) and concluded that this Settlement was a just and reasonable compromise of the issues presented in the case.[168]

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[163] Mullins, Exh. BGM 17-T at 2. The increase, taken to two decimal places is .99 percent. This is more appropriately rounded up to 1.0 percent rather than down, to .9 percent.

[164] *Id*. The decrease, taken to two decimal places is 3.88 percent. This is more appropriately rounded up to 3.9 percent rather than down, to 3.8 percent.

[165] *Id*.

[166] Al-Jabir, Exh. AZA 7-T at 2:4-7.

[167] Townsend, Exh. NT-1T at 2:19-21.

[168] Schooley/Cheesman, Exh. TES-4T at 2:11-3:5.

153 Considering the overall settlement, they testified in addition that:

> Staff is pleased to support the Settlement as a major and historic accomplishment by all the Settling Parties. The diversity of opinions expressed in testimonies could lead to many possible outcomes, any of which could be decided by the Commission as in the public interest. The outcome embedded in this Settlement represents many "gives and takes" and compromises by the Settling Parties and is a tribute to all parties trying to reach what is, in total, in the public interest. To do so with only a one percent increase in electric rates and a four percent decrease in gas rates is astonishing. Staff recommends the Commission accept the Settlement in its entirety, without condition.[169]

154 PSE's settlement witnesses testified that "PSE and the Settling Parties have compromised to reach a fair, just, reasonable, and sufficient revenue requirement and cost of capital for PSE."[170] They state, in addition, reflecting on the settlement outcomes concerning revenue requirements and rates, that:

> [T]he proposed Settlement satisfies the public interest because it will result in overall rates that are fair, just, reasonable and sufficient. In terms of customer benefits, the natural gas rates that will result from this agreement will provide an immediate overall rate reduction of 3.8 percent to PSE customers, which is beyond the decreases proposed by PSE in its direct and rebuttal filing. The resulting increase to overall electric rates is less than those proposed by PSE in its direct and rebuttal filing and represents an approximate one percent increase in overall electric rates compared to the 2.7 percent increase proposed by PSE in its rebuttal filing.[171]

Commission Determination

155 We reject Public Counsel's "alternative viewpoint" concerning overall revenue requirements and find on the basis of the discussion here, and our discussion below concerning specific adjustments to revenue requirements, that the Settlement Stipulation

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[169] Schooley/Cheesman, Exh. TES-4T at 22:8-17.

[170] Exh. PSE-1JT at 3:7-8.

[171] Exh. PSE-1JT at 15:1-9.

satisfies the public interest because it reaches end results in terms of overall rates that are fair, just, reasonable and sufficient.[172]

2. Depreciation Study (Natural Gas Adjustment 11.06)

a. Settlement Stipulation

156 As previously noted, the Settling Parties agreed to use the depreciation study provided by PSE as the basis for this adjustment, resulting in a $13,174,098 increase to net operating income (NOI) for natural gas operations and a $6,587,049 increase to natural gas rate base.[173] The Settling Parties state in their Settlement Stipulation that this issue is uncontested.[174] While it is true that accepting PSE's natural gas depreciation study resolved any disputes over this issue presented through the response testimonies of Staff and several intervenor parties, their agreement did not resolve Public Counsel's challenge to PSE's depreciation study for natural gas.[175] Public Counsel relies on Ms. McCullar's Response Testimony for its "recommendation on this adjustment."[176]

b. Public Counsel's Recommendation

157 Public Counsel's recommendations concerning the measurement and inclusion of net salvage for natural gas assets in depreciation rates would use more positive measures of net salvage value, thus lowering depreciation rates relative to what PSE proposed.[177] It is not clear from Ms. McCullar's testimony what she relied on to derive her proposed measures. She simply reports her results without explaining her methodology.

158 Ms. McCullar testified in her response testimony that she based her recommendation on a comparison of PSE's and her own proposed depreciation accruals going forward and "the actual average net salvage costs PSE has incurred over the recent five-year period 2011-2015." Because her approach resulted in lower annual accruals of net salvage than PSE's, Ms. McCullar testified that her "recommended future net salvage accrual," like PSE's,

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[172] *See Fed. Power Comm'n v. Hope Nat. Gas Co., (Hope)* 320 U.S. 591, 64 S. Ct. 281, 88 L. Ed. 333 (1944); *Bluefield Waterworks & Imp. Co. v. Pub. Serv. Comm'n of W. Va.*, (*Bluefield*) 262 U.S. 679, 43 S. Ct. 675, 67 L. Ed. 1176 (1923).

[173] *Supra* n.65.

[174] Settlement Stipulation ¶28.

[175] Colamonici, Exh. CAC-1T at 4:15-17; 12:27-28.

[176] Colamonici, Exh. CAC-1T at 12:28-30.

[177] *See generally* McCullar, Exh. RMM-1T at 18:1-25:3.

will "provide a reserve for estimated future net salvage costs, but at a more reasonable annual amount."[178] When asked to explain how Public Counsel's proposed net salvage accrual is more reasonable than PSE's, Ms. McCullar replied:

> Public Counsel's proposed net salvage accrual is more reasonable than PSE's proposed net salvage accrual based on analysis of the recent five-year period. PSE's proposed net salvage accrual of 4.3 times the actual incurred unnecessarily accelerates the building of the book reserve for future estimated net salvage costs, which increases the depreciation expense charged to current customers. However, Public Counsel's proposed net salvage accrual is 2.5 times the actual incurred [by] PSE, which will build the book reserve for future estimated net salvage costs at a more reasonable rate. Public Counsel's proposed net salvage accrual is a good balance between the depreciation expense charged to current customers and the building of the book reserve to cover any PSE future net salvage costs associated with the retirement of an asset.[179]

This, however, seems to do no more than reiterate Ms. McCullar's otherwise unsupported conclusion that because she advocates slower growth in the accrual reserves relative to historic actuals than does PSE, her recommendation is therefore "more reasonable than PSE's."

159 Mr. Spanos testified that he estimated net salvage based on statistical analyses performed by comparing historical cost of removal and gross salvage to historical retirements as recorded in PSE's property records. He analyzed both annual activity and longer and shorter term averages of the experienced net salvage expressed as a percent of retirements.[180] He verified that his approach "is consistent with the approaches described in authoritative depreciation texts," including the National Association of Regulatory Utility Commissioners' *Public Utility Depreciation Practices* (the "NARUC Manual") and *Depreciation Systems* by Wolf and Fitch. Mr. Spanos said that both these authoritative sources support that net salvage should be accrued over the life of the related property and should be estimated using the methodology he used.[181] In contrast,

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[178] McCullar, Exh. RMM-1T at 23:1-3.

[179] McCullar, Exh. RMM-1T at 24:10-19.

[180] Spanos, Exh. JJS-4T at 19:8-17.

[181] *Id.; see id.* at 21:15-24:8 for a detailed discussion of these texts; *see also* Barnard, Exh. KJB-56X (Excerpt from *Depreciation Systems*, Wolf and Fitch, Chapters 4 and 14, Iowa State University Press (1994) (Originally designated as Spanos, Exh. JJS-8X) and McCullar, Exh.

Mr. Spanos said that these texts do not support Ms. McCullar's approach and he is not familiar with any authoritative source that supports her approach.[182]

160 Mr. Spanos said he found Ms. McCullar to be unclear with respect to the methodology she used. He described her net salvage estimates as being "arbitrarily based on a false premise that net salvage accruals should be similar to recent net salvage expenditures."[183] The NARUC Manual explains that "net salvage is expressed as a percentage of plant retired by dividing the dollars of net salvage by the dollars of original cost of plant retired."[184] This methodology, in other words, recognizes net salvage as part of depreciation expense, not operating expense.

161 In addition, net salvage is a function of the number of assets retired in a given year and this may vary considerably from year to year.[185] Mr. Spanos criticizes Ms. McCullar's methodology because it fails to recognize this, "effectively assuming that PSE will experience the same net salvage costs independent of whether it retires 100 poles or 1,000 poles."[186]

162 Mr. Spanos found Ms. McCullar's comparison of net salvage accruals with net salvage expenditures PSE incurred during recent years to be "not a particularly meaningful comparison,"[187] and suggests a belief that annual net salvage accruals should approximate, or even be the same as, costs incurred during the same year. This, he testified, would effectively recover net salvage as an operating expense "instead of recovering the service value of assets over the assets' service lives."[188] According to Mr. Spanos, while Ms. McCullar's approach would result in lower revenue requirements today, it would result in less than full recovery of net salvage for plant in service, deferring a portion of removal costs for recovery from future customers.[189] The survivor

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RMM-6 (excerpt from NARUC's *Public Utility Depreciation Practices* (August 1996)). We supplemented RMM-6 indirectly by taking official notice Chapter XIII of the NARUC *Public Utility Depreciation Practices* Manual at TR. 554:7-17.

[182] Spanos, Exh. JJS-4T at 24:5-8.

[183] Spanos, Exh. JJS-4T at 19:19-21.

[184] Spanos, Exh. JJS-4T at 23:22-24 (citing NARUC Manual at 18).

[185] Spanos, Exh. JJS-4T at 20:20:22-21:1.

[186] Spanos, Exh. JJS-4T at 21:1-14.

[187] Spanos, Exh. JJS-4T at 20:1-4.

[188] Spanos, Exh. JJS-4T at 20:8-9.

[189] Spanos, Exh. JJS-4T at 20:9-14.

curve for these assets shows that "many more mains should be expected to retire on an annual level in the future than has occurred in the recent past."[190]

163 Mr. Spanos illustrated how Ms. McCullar's approach is flawed by providing detailed discussion of Gas Account 376.2 Mains Plastic and Gas Account 376.4 Mains – Wrapped Steel, which Ms. McCullar discusses as examples to support her position. He shows Ms. McCullar's failure to consider that all of the assets in Account 376.2 are relatively new and have a relatively long expected life of 60 years. Both accounts are relatively young, particularly when compared to the overall average service life for each account. As a result, both retirements and net salvage should be expected to occur at much higher levels in the future than has occurred in recent years.[191]

Commission Determination

164 Public Counsel's proposed alternative to the Settlement Stipulation's treatment of net salvage of mass assets used in natural gas operations appears to be based on testimony by Ms. McCullar that we find to be vague in its methodology, not supported by authoritative accounting literature, and supported by unwarranted assumptions. Mr. Spanos' estimates of net salvage for natural gas mass assets, in contrast, does not suffer from these deficiencies.

165 In addition, Ms. McCullar's comparison of net salvage accruals to net salvage expenditures PSE incurred during recent years would effectively recover net salvage as an operating expense, not a depreciation expense. We do not accept this result.

166 Thus, we reject Public Counsel's alternative viewpoint and approve the Settlement Stipulation with respect to net salvage of mass assets that support PSE's natural gas operations.

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[190] Spanos, Exh. JJS-4T at 27:1-2.

[191] Spanos, Exh. JJS-4T at 25:3-26:7:13.

3. Pension Plan (Electric Adjustment 13.15; Natural Gas Adjustment 11.15)

167 The Settling Parties agree to use the adjustments proposed by PSE and Staff. The agreed adjustments include a decrease for electric NOI of $1,184,945 and a decrease in natural gas NOI of $572,091.[192]

168 Public Counsel argues in its Initial Brief only that "Public Counsel witness Mr. Smith provided testimony on specific adjustments," and that it "incorporates" Mr. Smith's testimony into its Initial Brief for the Commission's "consideration." While we expect more complete argument in brief when a party opposes a specific term in the Settlement Stipulation, we nevertheless consider fully below both PSE's direct testimony that supports the Settling Parties' agreement on this issue and Public Counsel's response testimony that expresses its "alternative view" and preferred outcome.

a. PSE Direct Case Supporting Settlement Stipulation

169 PSE's witness, Mr. Hunt, provides an overview of the Company's current pension plans and provides illustrative exhibits of the current and future estimated service costs, contributions, and program valuation. Mr. Hunt testifies that PSE contributed $24 million to the pension plan during 2016.

170 PSE revenue requirement witnesses, Ms. Barnard (electric) and Ms. Free (gas), provide additional testimony on the pension expense calculation. Both testify that the Company calculated the restating adjustment for pension expense using a four-year average of cash contributions to the PSE qualified retirement fund.[193] Ms. Free testified that the Commission previously approved this methodology in the Company's 2009 general rate case. She testified more substantively that using cash contributions instead of expenses recognized under Financial Accounting Standards Board (FASB) codifications, including Financial Accounting Standard (FAS) 87, allows for consistency when applying this adjustment.[194] The four-year average contributions the Company allocated between electric and gas is $21.2 million for the test period ending September 30, 2016.[195]

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[192] Settlement Stipulation ¶ 46 (citing Cheesman, Exh. MCC-2r at 4; Barnard, Exh. KJB-19 at 4 (labeled there as "Adjustment No. 20.15 – Pension Plan")); *Id.* ¶47 (citing Cheesman, Exh. MCC-7r at 3; Free, Exh. SEF-14 at 3 (labeled there as "Adjustment No. 15.15 – Pension Plan")).

[193] Barnard, Exh. KJB-1T at 36:16-17; Free, Exh. No. SEF-1T at 18:21-22.

[194] Free, Exh. SEF-1T at 19:1-5.

[195] Free, Exh. SEF-1T at 19:7-9.

b. Public Counsel Response Testimony

171 Public Counsel's witness, Mr. Smith, proposed using the four-year average of net periodic pension cost for the period ending December 31, 2016.[196] He supported the use of a four-year average to normalize the expense allowance and remain consistent with prior Commission practice.[197] Mr. Smith provided detailed testimony that walks the Commission through the history of Financial Accounting Standard (FAS) 87, and funding requirements established by the Employee Retirement Income Security Act (ERISA) and the Pension Protection Act of 2006.

172 Opposing PSE's recommendation to continue using cash contributions to determine pension expense for ratemaking purposes, Mr. Smith testified that cash contributions to a utility's pension plan in any given year allow for a wide range of discretion. On the low end of the range, the Company is required to meet the minimum funding obligation (full funding)[198] while the ceiling is the maximum tax-deductible funding contribution.[199] He acknowledged that the level of cash contribution determined by the Company impacts the net periodic pension cost, predominately in the expected return portion of the calculation that subsequently reduces the net periodic pension cost.[200]

173 Additionally, Mr. Smith argued the Company's proposal overstates the 2018 rate year pension expense,[201] pointing to the data in one of Mr. Hunt's exhibits and his graphic representation of that data.[202] Mr. Smith's analysis identified approximately $3.0 million in what he considers to be overstated expense under PSE's proposal. Public Counsel's recommendation allows for $18.4 million in pension expense.

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[196] The net Periodic Pension Cost Formula is: Service Cost + Interest Cost – Return on Plan Assets +/- Amortization of Deferred Net Loss or Net Gain.

[197] Smith, Exh. RCS-1CT at 56:11-13.

[198] "The full-funding limit is defined as the lesser of 100 percent of the plan's actuarial accrued liability (including normal cost) or 150 percent of the plan's current liability." Smith, Exh. No. RCS-1CT at 53:21-54:1.

[199] Smith, Exh. RCS-1CT at 55:3-12.

[200] Smith, Exh. RCS-1CT at 55:16-20.

[201] Smith, Exh. RCS-1CT at 57:7-8.

[202] *See* Exh. RCS-12C.

c. PSE Rebuttal Testimony

174 Responding to Mr. Smith's recommendation to use the four-year average FAS 87 actuarial pension expense, Ms. Barnard testified that the components of his calculation are based on estimates and are not known and measureable. Additionally, she stated that FAS 87 is based on assumptions made today for transactions in the future, suggesting this is similar to the Accounting Standards Codification (ASC) 815 Derivatives and Hedging, formerly FAS 133, where it is recognized that the costs appropriate for inclusion in rates are not the same as those reported for GAAP purposes.[203] Ms. Barnard testified that the contribution method PSE used reflects the actual cash paid by the Company resulting in a known and measureable expense that better aligns with the cash basis for accounting used in rate setting.[204] Finally, Ms. Barnard argued Mr. Smith did not provide a fully developed record to support his adjustment and that his testimony "merely concludes that PSE's projected[205] pension contributions are higher than its projected FAS 87 expense and, therefore, moving to the FAS 87 expense should be accepted."[206]

175 Ms. Barnard also addressed Public Counsel's claim that management has a wide range of discretion as to the amount of pension contributions each year. First, she characterized today's pension environment as "heavily scrutinized" thus serving as a natural check and balance system for the contribution rates set by companies.[207] Second, she testified PSE has no incentive to under- or over-contribute to the fund. Ms. Barnard pointed to the same federal regulations that Mr. Smith did for a fully-funded pension trust, identified the premium (penalty) by the Pension Benefit Guaranty Corporation for underfunding, and pointed to PSE's limited cash flow coupled with the acknowledgement that the cash contributed may never be taken back from the pension trust to avoid overfunding.[208]

176 Finally, Ms. Barnard testified to the importance of consistency. She recommends the Commission maintain the use of the cash basis methodology to ensure PSE customers do not pay more or less simply because of changing methods, thereby supporting her

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[203] Barnard, Exh. KJB-17T at 39:16-41:4.

[204] Barnard, Exh. KJB-17T at 41:16-42:2.

[205] The term "projected" here refers to Mr. Hunt's exhibit TMH-7C, not the inclusion of projected pension expense in rates.

[206] Barnard, Exh. KJB-17T at 43:10-12.

[207] Barnard, Exh. KJB-17T at 43:15-17.

[208] Barnard, Exh. KJB-17T at 43:17-44:1; 44:17-45:2.

position to continue the use of the four-year average cash contributions to determine the pension expense included in general rates.[209]

Commission Determination

177 We find that PSE's approach to determining pension expense, accepted in the Settlement Stipulation, follows the Commission's long-held regulatory treatment of using a four-year average of cash contributions for setting rates, and is the appropriate methodology.[210] Public Counsel has not presented a compelling reason to alter this approach.

4. Environmental Remediation (Non-Colstrip) (Electric Adjustment 13.19; Natural Gas Adjustment 11.19)

a. Settlement Stipulation

178 The Settling Parties agree to use the adjustment for non-Colstrip Environmental Remediation proposed by PSE. This decreases electric NOI by $925,460 and natural gas NOI by $5,592,128.[211] The Settlement Stipulation provides that within six months of approving the settlement, the Commission will initiate a process to determine a methodology for assigning insurance recoveries with annual environmental reports.

179 PSE requested in this case to recover amortization of deferred environmental remediation costs incurred from 2000 through 2016. PSE proposes to offset the deferred remediation costs with a portion of the third-party payments and insurance recoveries it has received. PSE would set aside the remaining portion of the recoveries to offset its estimated future environmental remediation liabilities.[8]

180 PSE Witness Mr. Rork provided a description of PSE's environmental remediation sites, most of which are former manufactured gas sites that operated during the middle part of the 20th Century extracting methane from coal and oil. These sites represent PSE's most

[209] Barnard, Exh. KJB-17T at 47:15-20.

[210] *See* Barnard, KJB-17T at 38:16-47:20.

[211] Settlement Stipulation ¶47 (citing Barnard, Exh. KJB-19 at 4 (labeled there as "Adjustment No. 20.19 – Environmental Remediation")); *Id*. ¶48 (citing Free, Exh. SEF-14 at 4 (labeled there as "Adjustment No. 15.19 – Environmental Remediation")).

significant cost exposure for remediation responsibilities aside from Colstrip, which we discuss separately above.[212]

181 Mr. Rork's testimony included an overview of the Company's management and accounting of its environmental remediation responsibilities. He also testified that the costs PSE has deferred for environmental remediation are reasonable and the result of prudent operations.[213] According to Mr. Rork, "PSE performs all remediation activities in compliance with applicable federal and state laws and regulations,"[214] and is careful to take responsibility for remediation only of sites where it contributed to the contamination. He stated that PSE pursued third-party and insurance recoveries where available and works diligently to fulfill its remediation responsibilities cost-effectively.[215]

182 Mr. Rork testified that the remediation process typically is complex and requires implementation over many years.[216] Thus, he said:

> PSE will have continuing remediation obligations at some sites, and ongoing monitoring obligations at other sites. Under the applicable laws governing remediation, these obligations can continue for substantial periods of time or even indefinitely. As such, PSE expects that some level of continuing environmental remediation costs will continue for the foreseeable future.[217]

183 Ms. Free testified concerning PSE's rate recovery recommendation for non-Colstrip environmental remediation costs. She explained that PSE has had deferred accounting for its environmental remediation costs and recoveries since the early 1990s.[218] Indeed, the gas environmental treatment was approved in Docket UG-920781 in 1992. In a 2008 order approving an accounting petition from PSE, the Commission said with respect to certain electric remediation sites:

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[212] Rork, Exh. JKR-1T at 2:13-16.

[213] Rork, Exh. JKR-1T at 11:1 – 13:16.

[214] Rork, Exh. JKR-1T at 11:11-12.

[215] Rork, Exh. JKR-1T at 12:12-22.

[216] Rork, Exh. JKR-1T at 12:6-7.

[217] Rork, Exh. JKR-1T at 13:8-16.

[218] Free, Exh. SEF-1T at 23:17-18.

> Allowed net deferred costs will be amortized over a five year period on the date all costs, net of recoveries, become known and declared prudent. The deferrals will be consistent with the Commission's Merger Order in Docket UE-960195.[219]

Ms. Free testified that this brought the treatment of environmental deferrals into alignment for electric and gas operations.[220]

184 In this case, Ms. Free testified, PSE seeks recovery of certain of its net deferred environmental costs because the potential for future recoveries from insurance policies has declined in relation to amounts previously recovered. In addition, although there are still some viable third-party claims that remain, PSE believes it has substantially exhausted known third-party claims for remediation sites.[221]

185 Ms. Free testified that the amount of deferred net costs PSE seeks to recover in this case was determined considering only actual costs through September 30, 2016, which PSE expected to, and did, update to more current amounts during this proceeding. In order to maintain insurance and third-party recoveries to offset future remediation costs on existing environmental sites, PSE proposed to include only a portion of the unassigned insurance and third party recoveries to offset the actual costs included in this proceeding. PSE segregated insurance and third-party recoveries into two categories—site specific and unassigned. Actual site specific recoveries were assigned 100 percent against the actual September 30, 2016 deferred costs for those sites. The portion of unassigned recoveries to apply against all September 30, 2016, deferred costs was determined by taking the actual costs as of September 30, 2016, as a proportion of the estimated total cost of all existing remediation projects. The estimated total cost was determined as the midpoint between the high and low estimate of total future costs. Consistent with Order 01 in Docket UE-070724,[222] PSE proposed a five-year amortization period for the net deferred costs.

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[219] *In the Matter of the Petition of Puget Sound Energy, Inc., for an Accounting Order Regarding the Accounting Treatment for Costs of its Electric Environmental Remediation Program,* Docket UE-070724, Order 01 ¶6 (October 8, 2008).

[220] Free, Exh. SEF-1T at 24:1-9,

[221] Free, Exh. SEF-1T at 24:10-15.

[222] *In the Matter of the Petition of Puget Sound Energy, Inc., for an Accounting Order Regarding the Accounting Treatment for Costs of its Electric Environmental Remediation Program,* Docket UE-070724, Order 01 ¶6 (October 8, 2008).

b. Public Counsel

186 Public Counsel's position is that PSE should be required to use 100 percent of the insurance recoveries balance on its books to offset current liabilities.[223] Mr. Smith testified that "[t]his contrasts with PSE's proposal to only use 46 percent of the electric related proceeds and 58 percent of the gas related proceeds to offset environmental remediation costs through the end of the test year."[224] According to Mr. Smith, PSE's proposal creates a mismatch between costs and recoveries because future costs that PSE wishes to offset are not known and measurable.[225]

187 Ms. Free responded in her rebuttal testimony directly to Mr. Smith's testimony concerning the alleged mismatch between *expenditures* and recoveries, arguing it is Mr. Smith's proposal, not PSE's, that would create a mismatch between *costs* and recoveries. Ms. Free discusses the problem of intergenerational inequity as a factor weighing against use of all unassigned recoveries to offset existing deferred cost balances. She testified that:

> The insurance policies and third-party recoveries PSE has obtained are intended to cover costs for past, present, and future environmental remediation on the covered sites. Applying all of these proceeds to past and current costs would unnecessarily harm future customers who would be responsible for paying for remediation costs without receiving the offsetting benefit of related insurance recoveries. Likewise, existing customers would receive a disproportionate amount of the insurance recoveries while only paying a portion of the related remediation costs.[226]

188 Mr. Secrist testified for PSE in rebuttal identifying another reason to carry unassigned recoveries on the Company's books. Mr. Secrist said that assigning recoveries to specific environmental remediation projects prior to exhausting all litigation and insurance recoveries could result ultimately in the recovery of fewer funds for the benefit of ratepayers. Mr. Secrist described litigation in which an insurer attempted to have its

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[223] Colamonici, Exh. CAC-1T at 10:9-14 (with reference to Smith, Exh. RCS-1CT at 59-65). Ms. Colamonici testified that "This adjustment decreases electric net operating income by $552,786 and decreases natural gas net operating income by $2,850,219." It is not clear, however, whether this is a proposed adjustment to per books or to PSE's original proposal.

[224] Smith, Exh. RCS-1CT at 65:7-10.

[225] Smith, Exh. RCS-1CT at 64:5-65:3.

[226] Free, Exh. SEF-12T at 24:3-14.

liability reduced by assigning some of the recoveries PSE had received, but not assigned, to the environmental remediation project that was the subject of the litigation.[227] According to Mr. Secrist, this legal tactic did not succeed because PSE had not assigned the recoveries to that project.[228]

Commission Determination

189 The fundamental issue here is whether PSE should be required to use 100 percent of the insurance and third-party recoveries in deferral balances on its books to offset current liabilities or should be allowed to carry on its books the unassigned portions of those costs to offset future liabilities. Considering Ms. Free's and Mr. Secrist's rebuttal testimonies, we can restate this as two questions: 1) whether we should approve the Settling Parties' recommendation to continue carrying a portion of deferred recoveries in the interests of protecting the Company's ability to maximize recovery of unassigned environmental remediation costs and; 2) whether maintaining part of the current deferrals will avoid intergenerational inequities that will occur if all deferred recoveries to date are used to benefit current ratepayers, leaving none of these funds available to offset future costs that are certain to occur but in uncertain amounts and at uncertain times.

190 The Commission provided Public Counsel the opportunity to file testimony concerning the proposed settlement's adoption of (1) PSE's proposal to continue deferring the unassigned portion of its cost recoveries subject to detailed reporting requirements, and (2) the requirement that within six months of approving the settlement the Commission will initiate a process to determine a methodology for assigning insurance recoveries with annual environmental reports. Mr. Smith took this opportunity to testify that "Public Counsel generally supports the annual environmental reports and requirements listed in paragraph 55." However, Mr. Smith cited to his Response Testimony as support for his recommendation that 100 percent of recoveries be offset against current liabilities, apparently rejecting the idea that this question should be the subject of further study after this general rate case. Mr. Smith did not respond directly to PSE's concerns about potentially reduced recoveries going forward or intergenerational inequities.

191 Public Counsel argues in its Initial Brief that "the Settling Parties do not propose to use any of the electric or gas related proceeds to offset environmental remediation costs."[229] This is incorrect. The Settling Parties agree to use the adjustment for Environmental

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[227] Secrist, Exh. SRS-1T at 11:13-15.

[228] Secrist, Exh. SRS-1T at 11:15-18.

[229] Public Counsel Initial Brief ¶47.

Remediation proposed by PSE, which reflects PSE's proposal to use 46 percent of the electric-related insurance and settlement proceeds and 58 percent of the gas-related insurance and settlement proceeds to offset environmental remediation costs through the end of the test year. Under PSE's proposal, adopted by the Settling Parties, the unassigned balances in these accounts will be carried forward to offset future environmental remediation costs.

192 We favor the more deliberate approach recommended by the Settling Parties. This will provide immediate recovery though rates of significant third-party and insurance recoveries. It will also set aside significant funds to offset the costs that future generations of ratepayers will be expected to pay as environmental remediation efforts continue. Whether maintaining flexibility with respect to unassigned costs will help to maximize future recoveries is a more speculative question, but not one to be dismissed out of hand. The reporting requirements and commitment to a process that will bring greater clarity and certainty to the treatment of environmental remediation cost recoveries seems to us a more reasonable approach than simply earmarking 100 percent of the available funds for the benefit of current ratepayers.

193 Having discussed the record on this issue, and considering the parties arguments, we determine on balance that the interests of PSE's ratepayers, the Company, and the public interest are better served by our approval and adoption of the Settlement Stipulation's proposed resolution of this issue than by the alternative favored by Public Counsel.

5. Storm Damage (Electric Adjustment 14.05)

194 In its Initial Brief, as in the case of the Pension Expense Adjustments, Public Counsel's entire argument simply points out that "Public Counsel witness Mr. Smith provided testimony on specific adjustments." Public Counsel nominally "incorporates" Mr. Smith's testimony concerning storm damage into its brief for our "consideration." In this instance we are even less satisfied with Public Counsel's advocacy on this issue because the Settlement Stipulation reflects a detailed compromise of PSE's and Staff's fully developed and strongly divergent litigation positions. In the discussion below, we summarize the Settlement Stipulation's terms, which the Settling Parties ask us to adopt to resolve this issue. We also identify to the extent we can from Mr. Smith's testimony, the specific objections Public Counsel may have with respect to the Settling Parties' compromise.

a. Settlement Stipulation

195 Under the Settlement, PSE will defer the costs of any storms that occur on or after the Settlement Date and on or before December 31, 2017, under the terms of the storm loss deferral mechanism established in Order 6 in Dockets UE-040641 & UG-040640, *et al*., and as revised in Order 12 in Dockets UE-072300 & UG-072301 (the "Qualifying Storm Loss Deferral Mechanism"). PSE will propose amortization of any such storm costs deferred pursuant to the terms of the prior sentence for recovery in PSE's next general rate case or any ERF or limited rate proceeding to revise transmission and distribution rates.

196 PSE will retain the Qualifying Storm Loss Deferral Mechanism for any storm costs incurred on or after January 1, 2018, subject to the following modifications: (i) the cumulative annual cost threshold for deferral of storms under the Qualifying Storm Loss Deferral Mechanism will be increased from $8 million to $10 million, (ii) qualifying events that cost less than $500,000 will not qualify for deferral, and (iii) the cumulative annual cost threshold for the Qualifying Storm Loss Deferral Mechanism will exclude storm events with costs less than $500,000.

197 The Settling Parties agree to a six-year average of $10,656,246 for normalized storm expense.

198 The Settling Parties acknowledge that PSE has an over-amortization of $12,560,038 associated with the 2010 storms. PSE will use the over-amortization to absorb the remaining balance of December 2006 wind storm costs and the remaining balance of the over-amortization to reduce the balance of costs from the January 2012 snowstorm. PSE will amortize remaining storm deferrals, over four years, once approved for recovery in rates; provided, however, that PSE will amortize the January 2012 snowstorm over six years.

199 The Settling Parties agree that PSE will calculate normalized operating income, for purposes of PSE's Earnings Sharing Mechanism by removing the storm normalization adjustment from PSE's annual Commission Basis Report per WAC 480-100-257.

200 The Settling Parties agree that Adjustment No. 14.05 – Storm Damage decreases net operating income for electric operations by $6,137,438, the calculation of which is provided as Exhibit F to this Settlement.

b. Public Counsel

201 Asked in his Response Testimony whether he recommends any adjustments to the Company's proposed storm damage amortization expense, Mr. Smith answered:

> Yes, I am recommending one adjustment. Specifically, I recommend that the $60.3 million cost related to the January 2012 catastrophic Snowmageddon events be amortized over 10 years, rather than PSE's proposed six years. Reasons for this recommendation include the following:
>
> 1. Using a longer amortization period for this extremely costly storm will help ameliorate the rate impacts.
>
> 2. Using a longer amortization period is better correlated with the infrequent experience of storms as devastating and costly as the extraordinary January 2012 Snowmageddon event.

202 Mr. Smith acknowledged that PSE recognized, and proposed in its direct case to use a longer amortization period for the January 2012 storm. He referred specifically to Ms. Barnard's testimony that "[d]ue to the relative size of the balance, PSE proposes that this amount be amortized over six years instead of four years in order to mitigate rate impact on customers."[230]

203 Public Counsel's alternative recommendation of a 10 year amortization period for the January 2012 storm, would decrease electric net operating income by $5,776,213.39. Public Counsel referred to, and purports to "incorporate Mr. Smith's evidentiary presentation" into its brief for "the Commission's consideration." Public Counsel did not refer to any specific testimony by Mr. Smith and did not even cite to his testimony or exhibits. Public Counsel presented no argument in response to the resolution proposed in the Settlement Stipulation, to continue using the Qualifying Storm Loss Deferral Mechanism approved by prior Commission Orders, as referenced above.

Commission Determination

204 Public Counsel referred us in its initial brief to its "alternative viewpoint" of how PSE should account for storm damage. Public Counsel offered no reasoned argument or, indeed, any argument at all, supporting Mr. Smith's suggestion that PSE be required to use a 10-year amortization period for the storm events of January 2012. Mr. Smith's

[230] Smith, Exh. RCS-1CT at 36:17-19 (quoting Barnard, Exh. KJB-1T at 46).

testimony failed to demonstrate why, or how, his recommendation is somehow a better approach than the more incremental change from a 4-year to a 6-year amortization, the revised amortization period to which the Settling Parties agreed.

205 We determine on the basis of the full record on this issue that the Settlement Stipulation's proposed resolution is supported by substantial evidence and by our prior orders approving this approach to storm damage accounting and recovery. We find, in addition, that the Settlement Stipulation's proposal to use excess over-amortization of $12,560,038 associated with storm events in 2010 to absorb the remaining balance of the December 2006 wind storm, and to use the remaining balance of the over-amortization to reduce the balance of the January 2012 snowstorm, well-considered. These offsets will provide substantial benefits to ratepayers.

206 We approve and adopt, for the reasons discussed above, the Settlement Stipulation's Electric Adjustment 14.05 and the Settling Parties proposals for the treatment of storm damage costs going forward.

6. Plant Held for Future Use (Public Counsel Electric Adjustment B-5)

207 Three parties opposed PSE's adjustment in the category of Plant Held for Future Use: ICNU and NWIGU jointly, and Public Counsel. The Settlement Stipulation does not address Plant Held for Future Use. ICNU and NWIGU support the Settlement Stipulation as a resolution of all issues not expressly reserved for an adjudicated result. Thus, they have effectively abandoned their litigation position on this issue.

208 Public Counsel reiterated its litigation position through Ms. Colamonici's settlement testimony,[231] which relies on Public Counsel witness Mr. Smith's testimony. He recommended in his response testimony and his settlement testimony that we remove two portions of Kitsap Naval Land, considering the Commission's decision on plant held for future use in the Eleventh Supplemental Order in Dockets UE-920433, UE-920499, and UE-92162. Mr. Smith contends that this Order established a benchmark that would remove plant held for longer than 20 years. Public Counsel witness Mr. Smith's adjustment would decrease electric rate base by $436,566.[232]

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[231] Colamonici, Exh. CAC-1T at 10:15-11:2.

[232] Smith, Exh. RCS-3 Supplemental at tab KJB-12 column AR in response to BR 1B.

209 The Commission's 1993 order stated:

> The Commission is also concerned with the number of properties which have been held in this account for many, many years without action. Although litigation may cause some delays in a proposed use of property, some of the properties are apparently just "sitting". The Commission therefore adopts the Commission Staff's proposal for treatment of this account, including Mr. Martin's twenty-year benchmark for exclusion of properties. If property has not been acted on within twenty years, the ratepayers should not continue to bear these costs. The Commission specifically rejects the company's claim that establishment of a benchmark would be retroactive ratemaking. If that were the case, the Commission would never be able to establish reasonable guidelines.[233]

Mr. Smith testified the Kitsap Naval Land property was first included in plant held for future use on December 31, 1992. He argued the plant will have been held for nearly 27 years if put in service on the current projected date of October 1, 2019.

210 In rebuttal, PSE witness Mr. Marcelia testified to the benefits to ratepayers of holding assets in this account, and the consequence to ratepayers if the assets are removed from the utility's books. He stated:

> Almost all the assets in future use have appreciated in value. Once they are placed in service, the customers get the benefit of the historical (lower) cost of the asset. If PSE were to sell the assets and then repurchase them at a later date, the customer would almost certainly be worse off. If PSE were to remove the assets from future use to non-utility property, any gain on appreciation would be shared with shareholders. In contrast, any gain from the disposition of an asset in future use flows completely to customers. The sale of LSR Development Rights in 2014 provides an example.[234]

Mr. Marcelia also testified that the plant held consists almost exclusively of land that is unique in one way or another and not easily replaced if removed from the utility books.[235]

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[233] Smith, Exh. RCS-1T at 18:3-20 (citing *WUTC vs. Puget Sound Power & Light Company*, Dockets UE- 921262 *et al.* (consolidated), Eleventh Supplemental Order at 90 (Sept. 21, 1993)).

[234] Marcelia, Exh. MRM-1T at 13:15-14:1.

[235] Marcelia, Exh. MRM-1T at 14:2-4.

211 In addition, Ms. Barnard testified in rebuttal concerning the Kitsap Naval Land that, "These two properties have been held in future use longer than the 20 year period…because the timing of the transmission line for which the properties were acquired had to be extended as a result of the [Jefferson Public Utility District] transition."[236] Ms. Barnard stated further that the line upgrade for which the property was held is now anticipated to be in place by 2019.[237]

Commission Determination

212 PSE's planned use for the Kitsap Naval Land properties was delayed for a period of time due to circumstances outside the Company's control. It would be wasteful to require PSE to dispose of these lands now only to have to reacquire them later, if available, and probably at higher cost than the amount of proceeds that would be recovered through a sale today.

213 We are not persuaded that we should make Mr. Smith's recommended adjustments to this account. Indeed, we are convinced by Mr. Marcelia's and Ms. Barnard's testimony that it would be inappropriate and counterproductive, and to some extent punitive, to remove from rate base the Kitsap Naval Land properties that PSE plans to use in the relatively near future for a transmission project. We approve and adopt the Settlement Stipulation's proposed resolution of this issue.

V. Non-Revenue Issues Addressed in the Settlement Stipulation and Contested by Public Counsel

A. Expedited Rate Filing

1. Settlement Stipulation

214 The Settling Parties agree that PSE may file one ERF within one year after the effective date of the tariffs resulting from this proceeding that is consistent with the process and procedures used by the Commission in Dockets UE-130137 and UG-130138 and the parameters identified in Exhibit I to the Settlement Stipulation. Exhibit I provides that any ERF will be based on a Commission Basis Report (CBR) developed for a recently completed accounting period consistent with the approach defined in WAC 480-90-257 and WAC 480-100-257.

[236] Barnard, Exh. KJB-17T at 83:4-7.

[237] Barnard, Exh. KJB-17T at 83:8-9.

215 The ERF will use only restating adjustments most recently approved by the Commission, with the following exceptions:

(i) Use of end of period rate base is acceptable.

(ii) Annualization of any revenues that occurred after the test period and annualization of the underlying costs associated with those revenues to the extent not fully included in the test year results. This is necessary to maintain proper matching of the annualized revenue and expenses.

216 The ERF will remove power costs, purchased gas, and gas pipeline cost recovery mechanism related revenues, and expenses. Thus, only transmission, distribution, administration and general costs, and rate base will be used to determine the electric and natural gas revenue requirements to be considered in the expedited rate filing.

217 The ERF will use the rate of return established in the Company's most recent general rate case, except to update the interest rate on debt, if necessary.

218 The ERF will not include changes to rate spread or rate design from the most recently filed general rate case.

219 The Settling Parties will support, or not oppose, a schedule for an ERF that would allow rates to take effect within 120 calendar days after filing. Any subsequent ERF or limited rate proceeding filed by PSE will be required to be consistent with Commission guidance provided by rule or policy statement in Docket A-130355.

2. Public Counsel

220 Mr. Brosch testified for Public Counsel that the Company has not provided evidence as to why it needs an ERF.[238] Additionally, according to Ms. Colamonici, the terms in the Settlement regarding ERFs are ambiguous and unclear at best.[239] She testified, too, that the Settlement Stipulation concerning the ERF "inappropriately allows PSE to employ certain tools that are generally used to reduce regulatory lag without any demonstration that PSE needs such relief. One example is application of end of period rate base."[240] Ms. Colamonici also contends, with reference to Mr. Brosch's testimony, that "the ERF

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[238] Brosch, Exh. MLB-1T at 69.

[239] Colamonici, Exh. CAC-1T at 7:21-22.

[240] Colamonici, Exh. CAC-1T at 7:22-8:1.

proposal mistakenly assumes intervener [sic] parties have unlimited resources for participating in ERFs."[241]

Commission Determination

221 This term in the Settlement Stipulation provides guidance to the parties if PSE elects to seek rate relief between general rate cases, an option available to the Company in any event. In terms of what any such filing should include, we agree with the guidance offered by the Settlement Stipulation. Thus, we require that PSE and other parties follow the limits agreed to in the Settlement Stipulation for such a proceeding if filed within 12 months following the rate effective date of PSE's compliance filing in this proceeding. PSE will have the burden to show it needs such rate relief. The Commission retains the power to reject any ERF filing, approve it with or without modifications or conditions, or take such other action as it deems to be in the public interest. The Commission will endeavor to expedite the ERF process, but will not be bound by the parties' proposed 120-day schedule if it determines additional time is required to afford due process to all parties. PSE, of course, would be well-advised to be fully transparent and forthcoming with supporting schedules and workpapers at the time of any such filing so as to limit the need for discovery.

222 We do not find the Settlement Stipulation to be ambiguous or unclear in this connection. Our continuing willingness to accept the ERF concept here, contrary to what Public Counsel suggests, does not amount to preapproval of the use of end of period rate base or any other specific regulatory tool. Finally, while we sympathize with Ms. Colamonici's concern that "intervener [sic] parties [do not] have unlimited resources for participating in ERFs," we note that the ERF is by its terms a limited proceeding and all intervenors in this case support the Settlement Stipulation, including this provision.

B. Water Heater Program

1. Settlement Stipulation

223 PSE did not address this issue in its direct case. Staff witness Ms. O'Connell recommended in her response testimony that the Commission phase out PSE's rental programs in Schedules 71, 72, and 74 (rental programs).[242] The Settlement Stipulation provides that PSE will participate in a collaborative with Commission Staff and other

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[241] Colamonici, Exh. CAC-1T at 8:5-6.

[242] O'Connell, Exh. ECO-1CT at 25:18-31:2.

interested stakeholders to discuss the future of the water heater rental programs in PSE's natural gas Schedules.[243]

2. Public Counsel

224 Public Counsel filed no rebuttal or cross answering testimony on this issue. Nevertheless it recommended through Ms. Colamonici's testimony concerning the proposed Settlement Stipulation that the Commission should order the discontinuance of Schedules 71, 72, and 74.[244] This is based on Staff's litigation position, which Staff now has set aside in favor of a compromise on this issue.

Commission Determination

225 We determine that the Commission should approve the Settling Parties agreement to rely on a collaborative discussion by interested parties to give considered attention to this issue. Although Public Counsel adopts Staff's litigation position on this issue in opposing the Settlement, it would be inappropriate for the Commission to adopt a position Staff has compromised in favor of settlement and further discussion. A collaborative process will provide an opportunity for further discussion in which Public Counsel, and all interested parties, may participate.

C. SQI-5

1. Settlement Stipulation

226 PSE will revise Service Quality Index (SQI) No. 5 to establish an annual benchmark of 80 percent of calls answered within 60 seconds after a request to speak with a representative. This changes the standard that PSE must currently meet of answering 75 percent of calls within 30 seconds. The Settlement provides that the calculation will not include Integrated Voice Response System (IVR) transactions.

227 PSE observes in its Initial Brief that "the current SQI-5 metric was set two decades ago, when the methods available to customers to contact PSE were very different than today."[245] PSE argues it is reasonable for the Settling Parties "to agree to an updated metric reflecting the fact that many of the more basic calls are now handled through

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[243] Settlement Stipulation ¶123. PSE relied on Company witness Mr. Einstein who offered rebuttal to Ms. O'Connell's testimony. Einstein, Exh. WTE-1T at 1:13-22.

[244] Colamonici, Exh. CAC-1T at 15:9.

[245] PSE Initial Brief ¶ 18.

automated systems such as Integrated Voice Response."[246] PSE also argues that revising the SQI-5 standard to match what the Commission set for Avista two years ago is particularly reasonable considering that, "unlike Avista, PSE faces a $1.5 million annual penalty for failure to comply with its standard."[247] Ms. Barnard testified during Public Counsel's cross-examination that the Company's direct and rebuttal testimonies included significant documentation on why PSE supported changing the standard established in 1997 and that while Staff's litigation position was to maintain the status quo, the settlement includes a "compromised position."[248]

228 Responding to questions from the Bench, Mr. Schooley testified that Staff came to view the compromised position as being a reflection of improved technologies relative to 20 years ago that now allow the "easy questions" that come in to customer service centers to be handled by IVR. Other questions that are more involved and require conversation with a customer representative, "are ones that are much harder to deal with, so each question takes longer to answer for that customer."[249] Mr. Schooley testified that this means either allowing additional time for each call to be completed, resulting in slightly longer wait times for live responses to incoming calls, or overstaffing of customer service centers, which is inefficient.[250]

229 Mr. Collins testified for The Energy Project that The Energy Project' concern was that customers needing to make billing arrangements to address past due arrearages would be handled by a live person. He said The Energy Project "felt comfortable that this particular item allowed for that to occur since the SQI [is] specific to the live answer calls. So we were comfortable with that."[251]

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[246] PSE Initial Brief ¶ 18 (citing *See* Schooley, Tr. 606:19-607:18; *see also* Collins, Tr. 608:1-7).

[247] PSE Initial Brief ¶ 18 (citing *See WUTC v. Puget Sound Energy*, Docket UE-072300, Order 29 ¶ 13 (June 17, 2016) (referencing amendment to SQI program in 2007 general rate case that increased penalties to $1.5 million) *cf Avista Corp*, Dockets UE-140188 and UG-140189, Order 06 ¶¶ 13, 16-20 (declining to include penalties for Avista's service quality metric program); *see also TR. 591:24-592:2.*

[248] TR. 589:2-14; *see generally* TR. 589:2-592:8.

[249] TR. 607:3-6.

[250] TR. 607:7-11.

[251] TR. 608:1-7.

2. Public Counsel

230 Public Counsel, through its Initial Brief, opposes this change, arguing that it "gives PSE twice as much time to answer only five percent more calls."[252] According to Public Counsel, the proposed change to SQI-5 "erodes the foundation for which the Commission initially adopted the Service Quality Index" in connection with its approval of the merger of Washington Natural Gas Company and Puget Sound Power & Light Company during the mid-1990s. The Commission approved the standard to "provide a specific mechanism to assure customers that they will not experience deterioration in quality of service" and "to protect customers of PSE from poorly-targeted cost cutting."[253]

Commission Determination

231 We are persuaded by the record evidence and the arguments summarized above that it may be time to update the SQI-5 metric, especially considering how different communications technology and practice is today relative to 20 years ago. While we understand Public Counsel's concern about deterioration in customer service quality, we find that the Settling Parties' agreement on this issue is supported by the evidence, and is consistent with the public interest. To ensure that this change does not lead to deteriorating service for those customers trying to contact the Company by phone, we require PSE report to the Commission after one year of the change in this measure data concerning the customer's experience in contacting the company by phone, through the company's website and through the IVR methodology. Specifically, the Company must file evidence demonstrating that the new standard has not led to a deterioration in service quality and has not led to poorly targeting cost cutting.

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[252] Public Counsel Initial Brief ¶ 71.

[253] Public Counsel Initial Brief ¶ 71 (citing *In re Proposal by Puget Sound Power & Light Co. to Transfer Revenue from PRAM Rates to General Rates, In re Application of Puget Sound Power & Light Co. and Wash. Nat. Gas Co. for an Order Authorizing the Merger of Wash. Energy Co. and Wash. Nat. Gas Co. with and into Puget Sound Power & Light Co., and Authorizing the Issuance of Securities, Assumption of Obligations, Adoption of Tariffs, and Authorizations in Connection Therewith*, Dockets UE-951270 & UE-960195, Fourteenth Supplemental Order Accepting Stipulation; Approving Merger at 30 (Feb. 5, 1997); *Id.* at 32).

VI. Miscellaneous Uncontested Issues Addressed by the Settlement

A. Prudence

1. Settlement Stipulation

232 The Settling Parties agree to support a Commission determination that the following eight projects and actions were prudent and that PSE will fully recover its demonstrated costs:

- Snoqualmie Falls hydroelectric redevelopment project.
- Acquisition of the Buckley Natural Gas Distribution System.
- Acquisition and development of the Glacier Battery Storage System.
- Development and construction of the Ardmore Substation.
- Power purchase agreement with Public Utility District No. 1 Public Utility District No. 1 of Douglas County, Washington to purchase power from the Wells Hydroelectric Project.
- Acquisition of transmission capacity from Bonneville Power Administration (BPA) for the Goldendale Generation Facility (38 MW) and the Mint Farm Generation Facility (15 MW).
- Renewal of agreements for transmission capacity from BPA associated with the Coal Transition Power Purchase Agreement (100 MW), the Mint Farm Generation Facility (20 MW), and purchases from Garrison, Montana (94 MW).
- Total amount of actual costs accumulated and deferred until September 30, 2016, associated with PSE's electric and natural gas Environmental Remediation program.

233 PSE upgraded its Snoqualmie Falls facilities to ensure compliance with Federal Energy Regulatory Commission (FERC) relicensing requirements. Mr. Bamba provided detailed testimony concerning this project and its costs, which are now final.[254] Mr. Bamba testified among other things to the Commission's previous determinations in the Company's 2005, 2013, and 2014 PCORC proceedings in Dockets UE-050870, UE-130617, and UE-141141, respectively, that significant project costs incurred at those times were prudent.[255] Thus, approximately 75 percent of the total project costs already have been determined to be prudent and are being recovered in rates.

234 Mr. Mullally, Manager, Business Initiatives for PSE, testified in detail concerning PSE's purchase of the Buckley Natural Gas Distribution System; PSE's Glacier Battery Storage System pilot project; and PSE's agreement to purchase power from the Wells Hydroelectric Project. His testimony discusses, with respect to each of these projects,

[254] Bamba, Exh. RB-1T at 1:14-15:5

[255] Bamba, Exh. RB-1T at 3:3-11; 5:12-7:3.

PSE's evaluation of the project by cross-functional teams of internal experts and outside consultants including engineering and operations, gas supply and transportation, community and customer relations, legal, insurance, real estate, environmental, rates and regulatory, accounting, human resources, and financial planning and strategic initiatives.[256] Mr. Mullally also described how PSE kept management informed during the evaluation of these projects and identified key management decisions approving the projects and project costs. The status of each project and project costs also are part of Mr. Mullally's testimony. In addition, he discusses the benefits of each project to PSE and its customers.

235 Mr. Wetherbee testified with respect to PSE's acquisition of transmission capacity from BPA for the Goldendale Generation Facility (38 MW) and the Mint Farm Generation Facility (15 MW). He discussed that PSE relies on existing BPA transmission contracts from Mid-C to PSE's system to meet its capacity need in that the Company may use this transmission to wheel short-term market power from Mid-C to PSE's load.[257] PSE requires firm transmission from its generation resources and contracts in order to ensure reliable delivery to PSE's system to serve load, according to Mr. Wetherbee.[258] Mr. Wetherbee testified that "PSE performed a full and detailed justification for the reasonableness of the costs of renewing and acquiring these BPA transmission contracts."[259]

236 Concerning PSE's renewal of agreements for 100 MW of transmission capacity from BPA associated with the Coal Transition Power Purchase Agreement, Mr. Wetherbee said the Company's original contract with BPA for this capacity would have expired on September 26, 2016, but the Coal Transition PPA runs through 2025. PSE renewed the contract for five years to allow for continued delivery of power from the facility until September 20, 2021.[260]

237 Similarly, PSE's two contracts with BPA for 12 MW and 8 MW of transmission used to wheel power from Mint Farm would have expired November 15, 2015, and June 1, 2016, respectively. PSE renewed both contracts for additional five-year terms.[261]

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[256] *See, e.g.,* Mullally, Exh. MM-1T at 5:8-9:5.

[257] Wetherbee, Exh. PKW-1CT at 34:3-5.

[258] Wetherbee, Exh. PKW-1CT at 34:7-9.

[259] Wetherbee, Exh. PKW-1CT at 34:9-11.

[260] Wetherbee, Exh. PKW-1CT at 25:3-10.

[261] Wetherbee, Exh. PKW-1CT at 24:11-16.

238 Finally, Mr. Wetherbee testified concerning the expiration date of September 30, 2016, for the Company's 94 MW transmission contract that provides transmission from Garrison, Montana to the PSE system. This transmission supports PSE's wheeling of a 75 MW physical index power purchase during winter months, provides an alternative path, receiving at the Garrison 230 kV substation, to wheel power from PSE's generation assets in Montana if there are outages or derates on the 500 kV transmission system, and provides access to short-term power purchases at the Garrison hub at prices that are generally below Mid-C prices.[262] Mr. Wetherbee testified the Company evaluated its options in conjunction with the assumed replacement of the winter peaking physical index power purchase that expired in February 2015. The portfolio analysis showed a $27 million portfolio benefit associated with the 94 MW transmission renewal.

239 Staff testified in support of the settlement that it did not contest the prudence of these projects, agrees that they are prudent, and that the result reflected in the Settlement Stipulation "is fair."[263]

240 PSE did not address the Ardmore substation in its direct case. ICNU, in its response case, objected to the prudence of the costs PSE incurred in connection with the Ardmore substation development and raised concerns about the allocation of these costs.[264] Ms. Koch testified to this issue for PSE on rebuttal. She challenged ICNU witness Mullins's reliance on a planning document that did not reflect the actual final budget for this project. She testified that cost increases (and savings) for the project resulted from a variety of causes including an evolving scope of work over time associated with changing requirements, stakeholder input, property permitting costs, increased materials and construction costs, costs associated with adding Interlaken, constraints and opportunities in the area, and construction site conditions.[265] Ms. Koch stated that PSE followed standard practices including a competitive bid process and close monitoring of the project by management.[266] Ms. Koch explained that it would not have been reasonable for PSE to abandon the project as costs increased because project benefits also were "increased by absorbing the function of the Interlaken substation, eliminating the need to upgrade that

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[262] Wetherbee, Exh. PKW-1CT at 25:15-26:2.

[263] Schooley/Cheesman, Exh. TES-4T at 19:11-15.

[264] *See* Mullins, Exh. BGM-1T at 51:16-56:8.

[265] Koch, Exh. No. KAK-4T at 37:9-19. "Project Change Requests" contain the processes for approval for budget and associated scope changes. Exhibit CAK-8 provides a chronology of the entire project cost and scope details.

[266] Koch, Exh. No. KAK-4T at 41:19-42:13.

station and incur additional cost." Ultimately, ICNU compromised its litigation position by expressly agreeing to the prudency of these costs while reserving its right to address their allocation in a subsequent proceeding.[267]

2. Public Counsel

241 Ms. Colamonici testified that Public Counsel supports generally PSE's power costs as originally filed and is "neutral" with respect to the Glacier Battery Storage System, the Goldendale capacity upgrade, and the Mint Farm Capacity upgrade, specifically.[268] It appears, then, that the prudence of the projects identified above is not at issue.

Commission Determination

242 We find substantial competent evidence in the record, largely unrebutted, as discussed above and earlier in this Order,[269] supporting the prudence of these eight projects. We determine accordingly that the projects the Settling Parties identify in their Settlement Stipulation, as set forth above, should be found to be prudent.

VII. Issues that Remain in Dispute Outside the Settlement

A. Decoupling

243 The Commission approved PSE's decoupling mechanism in mid-2013 as part of the Rate Plan that is now drawing to a close.[270] It was designed to encourage PSE to place a greater emphasis on energy conservation by weakening the Company's incentive to increase revenue by increasing sales, *i.e.*, the throughput incentive. PSE's decoupling mechanism does this by separating out the Company's energy delivery costs and calculating them on a per-customer basis. Once that figure has been determined, the amount of revenue PSE recovers through the decoupling mechanism is a simple calculation: revenue per customer multiplied by number of customers equals decoupling revenue.

244 The decoupling mechanism was designed with the various customer classes separated into four different rate groups. Each group's decoupling revenue is calculated

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[267] *See* Exh. PSE-1JT at 12:7-19.

[268] Colamonici, Exh. CAC-1T at 11:17-18, 12:14, 12:19, and 12:20-21.

[269] *See supra* ¶¶ 178-193.

[270] *See supra* n.1 (Order 07-2013 Rate Plan).

independently. This was done to limit cross-subsidization between classes with different load shapes.

245 The mechanism is set forth in a separate tariff, and guarantees PSE decoupling revenue recovery by allowing the Company to true up any revenue deficiencies each year. In each true-up filing, PSE's decoupling earnings are subject to a rate test, which determines how much revenue PSE was authorized to earn for the year based on how many customers it served, and then compares that figure to the decoupling revenue that PSE actually earned. If PSE did not recover its authorized decoupling revenue, the mechanism allows the Company to defer the unrecovered costs and increase the decoupling tariff to recover them in the following year. Annual rate increases are capped at 3 percent.

246 In tandem with the decoupling mechanism, the Commission instituted an earnings test for PSE. The earnings test applies to the Company's overall revenues – not just those collected through decoupling. The earnings test compares PSE's normalized revenue each year against its authorized revenue requirement, and requires the Company to share any earnings above its authorized revenue requirement with customers on a 50-50 basis.

247 In this case, PSE proposes to continue permanently its use of decoupling but recommends four major changes to the decoupling mechanism. Specifically, the Company asks the Commission to approve:

- Including fixed production costs for recovery via the decoupling mechanism.
- Re-alignment of the rate groups.
- Changes to the rate test and rate cap.
- Removal of normalizing adjustments from the earnings test.

248 ICNU and FEA recommend the Commission reject the Company's request to continue the decoupling mechanism. Staff, Public Counsel, NWEC/RNW/NRDC, Kroger, and The Energy Project support the continued use of the decoupling mechanism but do not agree with all four changes PSE recommends, or a permanent extension of the mechanism.

1. Should the Commission Approve PSE's Continued Use of Decoupling?

249 PSE argues that its contention that the decoupling mechanisms are operating as intended is supported by the evidence in this case.[271] Specifically, PSE cites to a third-party

[271] PSE Initial Brief ¶ 60.

evaluation of PSE's decoupling mechanisms conducted by Gil Peach and Associates. PSE says the study "confirmed the success of the decoupling mechanisms and specifically found that PSE is calculating decoupling deferrals and rates in accordance with Commission orders."[272] In addition, PSE argues that that "rate impacts have been small for electric customers and most gas customers, including low-income customers; conservation program performance has been stable during the evaluation period; and removing the throughput incentive has been a positive step in removing barriers to energy efficiency performance."[273]

250 Staff agrees that the decoupling mechanism should continue.[274] Staff argues that PSE's decoupling mechanism is successful because the Company has achieved higher levels of conservation and has experienced revenue stability.[275] Staff also supports the continuance of decoupling considering that PSE has committed itself to continuing its conservation achievement of five percent above its biennial conservation target, or suffer the consequence of penalties and proposes a natural gas conservation achievement of five percent above that contained in its integrated resource plan, coupled with a penalty for failure to meet this target.[276]

251 ICNU argues that decoupling is inconsistent with sound ratemaking practices, violates the Commission's governing statutes, and does not appropriately balance the interests of the Company with customers that take service under Schedules 46 and 49 (High Voltage).[277] The first two arguments depend on ICNU's perspective that PSE's revenue per customer decoupling design "allows it to charge customers for kilowatt hours never used by[,] and never before billed to[, the] customer."[278] That is, "the service received by a customer from PSE during a billing period no longer determines the monthly charge demanded by PSE."[279]

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[272] PSE Initial Brief ¶ 60.

[273] PSE Initial Brief ¶ 60 (citing s*ee* Piliaris, Exh. JAP-29 at 14-27).

[274] Staff Initial Brief ¶ 53 (citing Liu, Exh. JL-1CT at 27:7-8).

[275] *Id.* (citing Liu, Exh. JL-1CT at 26:4 - 27:4).

[276] *Id.* (citing Piliaris, Exh. JAP-1T at 144:17-21; 145:7-20).

[277] ICNU Initial Brief ¶ 42. Schedules 46 and 49 provide service to PSE's larger industrial customers.

[278] ICNU Initial Brief ¶ 44.

[279] ICNU Initial Brief ¶ 44.

252 Citing RCW 80.28.010 and .020, ICNU says the Commission's authority over rates "is expressly and undeniably linked to the services" it provides.[280] ICNU finds support for this proposition in "the seminal 1985 *Power* case" in which the Court said:

> In reading the *rate setting* statutes [citing RCW 80.28.010 and .020], it is clear that they are simply referring to "service rendered" in the context of utilities charging customers "for services rendered" or "services to be rendered" to their customers, and that these terms are used in much the same sense that lawyers charge their clients "for services rendered" and doctors charge their patients "for services rendered."[281]

It follows from this, ICNU argues, that "service must be *rendered* or otherwise delivered to the customer before charges for such services can be included in rates."[282]

The *POWER* case, however, supports the broad powers of the Commission to set rates under RCW 80.28.010 and .020. Indeed, the Court states unequivocally that "within a fairly broad range, regulatory agencies exercise substantial discretion in selecting the appropriate rate making methodology."[283] Decoupling is a deferred accounting mechanism that allows for annual true-ups. Both deferred accounting and true-up mechanisms are commonplace rate making methodologies that are widely used throughout the United States and routinely used by the Commission.

253 ICNU discusses two Washington telecommunications cases in which courts overturned Commission orders that approved rates or surcharges unrelated to services rendered.[284] ICNU argues that "[a]s in *Tracer* and *Jewell*, there is no connection between the deferred costs created by PSE's decoupling program and service rendered to the customers who would be required to pay rates to cover these deferred costs." [285] ICNU contends the decoupling charge on PSE's customers' bills is a charge that is "unrelated to service

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[280] ICNU Initial Brief ¶ 47.

[281] ICNU Initial Brief ¶ 48 (citing *People's Organization for Washington Energy Resources v. Washington Utilities and Transp. Comm'n,* 104 Wash.2d 798, 825 (1985) (*POWER*)).

[282] ICNU Initial Brief ¶ 49.

[283] *POWER*, 104 Wash.2d 798, 812.

[284] ICNU Initial Brief ¶¶50-51 (citing *Washington Independent Telephone Ass'n v. Telecommunications Ratepayers Ass'n for Cost-Based & Equitable Rates ("Tracer") 75 Wash. App. 356 (1994);* and *Jewell v. WUTC*, 90 Wn.2d 775 (1978)) (*Jewell*).

[285] ICNU Initial Brief ¶52.

provided by the company."[286] Because of this, ICNU says, the Commission should reject the Company's decoupling program.

254 *Tracer* and *Jewell*, however, are distinguished by the fact that, in both cases, the costs the Commission approved for recovery were completely unrelated to any utility service provided. In *Tracer* the court struck down a Commission rule that essentially required larger local exchange carriers (LECs), such as US West and AT&T, to pay into a fund that would subsidize smaller LECs. The Court ruled the Commission lacked power to impose what essentially was a tax allowing for cross-subsidization of smaller LECs by large ones.[287] In *Jewell*, the Court rejected the Commission's allowed recovery of charitable contributions, finding these did not result in customers receiving more prompt or expeditious service and the relevant statutes did not direct telephone companies to be "good corporate neighbor[s]."[288] PSE's decoupling mechanisms, in contrast, allow for recovery of fixed costs the Company incurs to deliver electricity and natural gas to its customers. Nothing could be more central to the utility's purpose.

255 FEA argues that "revenue decoupling is an inappropriate and unwarranted departure from traditional ratemaking principles.[289] According to FEA, revenue decoupling alters the traditional ratemaking process by allowing automatic adjustments to base rates outside of a general rate case to reflect the impact of changing sales levels over time. In FEA's opinion, this removes the Company's incentives to operate efficiently and promote economic growth in its service territory to improve its financial results between rate cases.[290] FEA argues in addition that decoupling has the effect of discouraging voluntary conservation efforts by customers because reduced sales result in higher revenue per customer charges between rate cases.[291] In addition, decoupling shifts the risks of a downturn in sales between rate cases to customers even if reduced sales result from abnormal weather conditions or a general economic downturn.[292] Absent a reduction in return to reflect this risk shifting, decoupling results in overcompensation to the

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[286] *Id.*

[287] *TRACER*, 75 Wn. App. 356, 361.

[288] *Jewell*, 90 Wn.2d 775, 777.

[289] FEA Initial Brief at 5.

[290] *Id.*

[291] Al-Jabir, Exh. AZA-1T at 7:1-7.

[292] Al-Jabir, Exh. AZA-1T at 7:11-24.

Company's shareholders.[293] FEA argues that decoupling makes the Company less responsive to its customers' needs and creates increased rate volatility in the event that an economic recession or abnormal weather causes a dramatic decline in sales between rate cases.[294]

256 NWEC/RNW/NRDC argue that empirical evidence in the form of two independent reviews of the performance of PSE's decoupling mechanism concluded that PSE's program is working as intended, with no identifiable problems.[295] The parties argue more specifically that:

> In both the Second- and Third-Year Reports, the consultants concluded that "[t]here is overall stability of good performance (energy efficiency and conservation achievement) in decoupling as compared with the time just prior to decoupling." The independent reviews found no evidence that decoupling had harmed customer service, as only one of 22 customer service indicators declined in the years after decoupling—and even for the one declining indicator, PSE's performance remained within the target values. The overall revenue impacts of decoupling have been small (*i.e.*, less than 2% of total revenues), and annual average O&M costs have grown at a lower rate after decoupling than historically. [296]

NWEC/RNW/NRDC said that FEA witness Mr. Al-Jabir opposes the extension of decoupling on the ground that it discourages customer investments in energy efficiency,[297] yet when asked to substantiate these claims, Mr. Al-Jabir responded that he

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[293] Al-Jabir, Exh. AZA-1T at 8:1-10.

[294] Al-Jabir, Exh. AZA-1T at 8:11-9:10.

[295] NWEC/RNW/NRDC Initial Brief ¶ 12 (citing Docket No. UE-121697, "Puget Sound Energy Electric and Natural Gas Decoupling Second Year Evaluation" by H. Gil Peach & Associates LLC with Forefront Economics, Inc. & Joseph Associates, Inc. (Apr. 14, 2016) ["*Second-Year Report"*]; Exh. JAP-29, "Puget Sound Energy Electric and Natural Gas Evaluation: Three Years of Decoupling" by H. Gil Peach & Associates LLC with Forefront Economics, Inc. & Joseph Associates, Inc. (Dec. 31, 2016) ["*Third-Year Report"*]).

[296] NWEC/RNW/NRDC Initial Brief ¶ 13 (citing *Second-Year Report* at 5; *see also Third-Year Report* at 20, 87-88, 94; *Second-Year Report* at 6; *Second-Year Report* at 2; *Third-Year Report* at 14-16, 55-57, 114).

[297] NWEC/RNW/NRDC Initial Brief ¶ 15 (citing Al-Jabir, Exh. AZA-1T at 5:17, 7:3-7).

had no supporting evidence.[298] Moreover, NWEC/RNW/NRDC argues "the financial benefits to customers from implementing energy efficiency measures exceed the decoupling adjustments, and the decoupling adjustments have been too small to discourage customer investments in energy conservation."[299]

257 In addition, NWEC/RNW/NRDC argues:

> [W]hile Mr. Al-Jabir claimed that decoupling reduces PSE's incentive to control costs, the Third-Year Report undermines Mr. Al-Jabir's claim by showing that O&M costs grew at a slower rate after decoupling than before decoupling. Likewise, when asked to provide evidence to support his claim that decoupling reduces PSE's incentive to provide quality customer service, Mr. Al-Jabir could provide no such evidence. Mr. Al-Jabir's claim is refuted by the record evidence, which shows that only one of 22 customer service indicators declined in the years after decoupling.[300]

258 PSE argues that the Commission should reject the recommendations by ICNU and FEA to discontinue PSE's decoupling mechanism because, among other reasons, "they rely on arguments that the Commission rejected when it authorized PSE's decoupling mechanisms just four years ago."[301] Moreover, PSE says the Gil Peach Report "concludes that there is no evidence that the decoupling mechanism created a disincentive for PSE's customers to conserve, that it does not have an adverse impact on PSE's service quality, and that it only leads to minor rate adjustments, particularly excluding the effects of the associated K-factor increases under the Rate Plan."[302]

259 Staff supports the continuation of PSE's decoupling mechanisms, but not on a permanent basis as PSE proposes. Staff argues that it should be only be extended for four years to ensure that the mechanism is regularly reviewed.[303] PSE argues, for the reasons stated in

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[298] NWEC/RNW/NRDC Initial Brief ¶ 15 (citing Exh. AML-14 (FEA Response to NWEC/RNW/NRDC Data Request No. 001)).

[299] NWEC/RNW/NRDC Initial Brief ¶ 15 (citing *Third-Year Report* at 138).

[300] NWEC/RNW/NRDC Initial Brief ¶ 16 (citing *See Third-Year Report* at 114; Piliaris, Exh. JAP-1T at 127:11-14; Exh. AML-15 (FEA Response to NWEC/RNW/NRDC Data Request No. 003); *Second-Year Report* at 6).

[301] PSE Initial Brief ¶ 63.

[302] Id. (citing Piliaris, Exh. JAP-29 at 130, Tables VII.5 and VII.6).

[303] Liu, Exh. JL-1CT at 62:3-13. *See also* Staff Initial Brief ¶¶ 55-59.

the preceding paragraph, that Commission Staff's proposal that PSE file within four years to renew its decoupling mechanisms should be rejected.[304]

Commission Determination

260 The Commission has addressed previously the legal and policy bases for decoupling. Specifically with respect to PSE, the Commission determined in 2013 that PSE's decoupling mechanisms were warranted, consistent with the State's energy policy and with the Commission's decoupling policy statement:

> The decoupling mechanisms we approve mean that PSE's recovery of the fixed costs it incurs for infrastructure and operations necessary to deliver power and natural gas will no longer depend on the amounts of electricity and natural gas the company sells. This removes the so-called throughput incentive, thus promoting PSE's more aggressive pursuit of cost-effective conservation to which it commits as part of the decoupling mechanisms. With the throughput incentive eliminated, the company will be indifferent to sales lost as a result of the success of its conservation efforts. The full decoupling approved here is the first utility -supported mechanism that is both generally consistent with, and truly targeted to achieve, this key objective embodied in the Commission's 2010 Decoupling Policy Statement.[305]

We discuss in some detail above, and earlier in this Order, PSE's evidence showing that decoupling is working as intended.[306] We find unpersuasive ICNU's argument that decoupling is illegal because it is not a charge for "services rendered." To the contrary, it is a rate methodology for recovering a defined portion of the fixed costs PSE incurs to deliver electricity and natural gas to its customers. Delivery of power and gas unquestionably are services rendered by PSE and the Company is entitled to recover its delivery costs by the means we establish through our orders in general rate cases consistent with both law and policy.

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[304] PSE Initial Brief ¶ 64.

[305] *In re PSE and NW Energy Coalition*, Dockets UE-121697 & UG-130137, Order 07, Synopsis at ii (June 25, 2013). *See In re WUTC Investigation into Energy Conservation Incentives,* Docket U-100522, Report and Policy Statement on Regulatory Mechanisms, including Decoupling, To Encourage Utilities To Meet or Exceed Their Conservation Targets at (Nov. 4, 2010) (Decoupling Policy Statement).

[306] *See supra.* ¶¶ 42-51.

261 We also are not persuaded by ICNU's and FEA's policy arguments that we have heard, and rejected, in earlier proceedings. In contrast, we find NWEC/RNW/NRDC's arguments, discussed above, to be sound and well supported. We have no need to revisit further decoupling's legal and policy justifications in the context of this general rate case. We determine that PSE will be authorized to continue using its decoupling mechanisms.

262 We agree with Staff, however, that it would be prudent for the Commission to review the operation of the mechanisms again after they have operated for four more years, especially given the modifications discussed below. We will wish to again review PSE's specific mechanisms in its first general rate case filed in or after 2021, or in a separate proceeding, if appropriate.

2. Should Non-Residential Customers be Regrouped; Should Some or All Large Non-residential Customers be Removed from the Decoupling Mechanisms?

263 PSE's current electric decoupling mechanism includes a residential electric rate group and three non-residential electric rate groups: (i) customers served under Schedules 12 and 26, (ii) customers served under Schedules 10 and 31, and (iii) the remaining non-residential rate schedules.[307] PSE proposes to separate the third group into three new groups, as follows:

- Customers served under Schedules 8 and 24: These customers have smaller use per customer and are so great in number and aggregate load that they tend to dominate the overall results for the existing non-residential group.[308]

- Customers served under Schedules 40, 46 and 49: These customers have significantly different load and service characteristics from the other customers in the existing non-residential group.[309]

- All remaining non-residential rate schedules that are currently in the third existing rate group.

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[307] *See* Piliaris JAP-1T at 130:1-6.

[308] *See id.* at 130:12-15.

[309] *Id.* at 130:9-12. All parties agree that Schedule 40 should be phased out during the rate year following from this Order.

264 Non-residential natural gas customers included in the decoupling mechanisms are presently in a single group.[310] PSE proposes two groups: (i) customers served under Schedules 31 and 31T, and (ii) all remaining non-residential gas customers that are currently in the decoupling mechanism. PSE argues that the large number of small commercial customers served under Schedules 31 and 31T tend to dominate the results for the rest of their existing decoupling rate group, and the remaining customers in the non-residential decoupling rate group have a use and revenue per customer more similar to one another than to customers served under Schedules 31 and 31T.[311]

265 In his testimony, Mr. Piliaris argues that dividing the largest of the non-residential electric groups into three new groups, and splitting the single non-residential group in the gas decoupling mechanism into two groups, will reduce cross subsidies by better aligning customers with similar load profiles.[312] PSE argues its proposals to regroup non-residential customer groups "walk a fine line."[313] This is because "[i]f decoupling groups are too big there may be cross subsidies of the customers within the decoupling group. If decoupling groups are too small, there may be rate volatility within the group."[314] PSE argues that its proposed regrouping balances appropriately the competing objectives of minimizing cross subsidies while mitigating rate volatility.

266 While Ms. Liu agrees with the Company's assessment that non-residential customers are improperly grouped, she presents an alternate plan that would remove all large industrial and irrigation customers from the electric decoupling mechanism altogether. Specifically, Staff proposes to remove electric Schedules 12/26, 10/31, 29, 35, 40, 43, 46 and 49. Staff proposes three decoupling groups for the remaining electric customers: residential (Schedule 7), small demand (schedules 8 and 24) and medium demand (schedules 7A, 11 and 25).[315] Ms. Liu testifies that decoupling is no longer appropriate for large industrial customers because it adds little value to conservation savings, it does not lend itself to relatively small groups of customers with diverse load profiles, and that rate design (*e.g.*, increased demand charges) is a more effective means of addressing the issue of revenue

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[310] *Id.* at 108:13-15. This includes Schedules 31, 31T, 41, 41T, 86 and 86T.

[311] *See* Piliaris, Exh. JAP-1T at 132:2-14.

[312] See Piliaris, Exh. JAP-1T at 131:10-16.

[313] PSE Initial Brief ¶ 65.

[314] PSE Initial Brief ¶ 65.

[315] Liu, Exh. JL-1CT at 30:15-31:6

stability from large customers. The Settling Parties agree to increase the demand charges for Schedules 46 and 49 by 48 percent as proposed by Commission Staff.[316]

267 On the natural gas side, Ms. Liu proposes realigning electric customers into three groups: residential (Schedule 23), small volume (Schedule 31) and large volume (Schedule 41), while removing interruptible customers on Schedules 86 and 86T from the mechanism.[317] Large natural gas customers on Schedules 85, 85T, 87 and 87T already have been removed from decoupling. Ms. Liu testified that their exclusion did not negatively affect the Company's conservation achievement.[318]

268 Mr. Higgins, for Kroger, filed cross-answering testimony supporting Staff's recommendation to remove large customers from the electric decoupling mechanism. He supports Staff's rationale that "rate design is a better tool than revenue decoupling to address the concern of fixed cost recovery for large customers."[319] He testified in addition that when "customers reduce usage in response to economic conditions or otherwise practice self-funded energy conservation, these behaviors are captured in the decoupling adjustment and unduly increase rates to customers."[320]

269 If the Commission continues the decoupling mechanism, FEA witness Mr. Al-Jabir recommends that large customers should be exempted because their demand charges remedy the revenue stability issue, and they already have significant economic incentive to pursue energy conservation.[321] Mr. Al-Jabir states that decoupling "penalizes customers for undertaking successful, voluntary energy efficiency efforts by increasing their distribution charges when their retail consumption levels decline between base rate cases."[322]

270 Testifying on behalf of ICNU, Mr. Gorman argues that if the Commission continues the decoupling mechanism it should no longer apply to large industrial customers on Schedules 40, 46, and 49, since those customers have steady load and enough of an

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[316] *See* Ball, Exh. JLB-1T at 54:3-10.

[317] Liu, Exh. JL-1CT at 31:11-17.

[318] Liu, Exh. JL-1CT at 35:8-11.

[319] Higgins, Exh. KCH-4T at 9:15-21.

[320] Higgins, Exh. KCH-1T at 15:19-21.

[321] Al-Jabir, Exh. AZA-1T at 11:14-12:7.

[322] Al-Jabir, Exh. AZA-1T at 7:3-5.

economic incentive to pursue conservation on their own.[323] Mr. Gorman testifies that "revenue stability can be accomplished through rate designs on those schedules,"[324] instead of through decoupling.[325]

271 Mr. Piliaris, testifying for PSE on rebuttal, recommends the Commission reject Staff's proposal to exclude large industrial customers from the electric decoupling mechanism, arguing that removing those customers' share of fixed production costs from the mechanism would amount to a collateral attack against the PCA settlement agreement that the Commission approved in Docket UE-130617. Mr. Piliaris argues that "[t]his alone should call into question any recommendation to move electric customers out of the decoupling mechanism."[326] He further contends that Staff's proposal fails to address how any remaining deferral balance associated with a class that exits the decoupling mechanism would be handled, and the Commission should reject the proposal based on that infirmity.[327]

272 PSE argues in its Initial Brief that the state's energy policy is to reduce electric utility companies' throughput incentive.[328] The Company states that

> The customers ICNU and FEA propose to exclude from the electric decoupling mechanism have among the largest declines in use per customer. To remove them from the decoupling mechanism would amplify PSE's throughput incentive, contrary to the state energy policy.[329]

273 Staff argues that PSE's throughput incentive "is not the deciding factor in this instance."[330] According to Staff, PSE's influence on large non-residential customers is limited to offering conservation rebates. Staff's analysis shows, however, that these customers are better able to respond to the conservation incentive inherent in their

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[323] Gorman, Exh. MPB-1T at 30:21-32:12

[324] TR 257:20-24.

[325] Gorman, Exh. MPG-7Tr at 4:20 - 5:4.

[326] Piliaris, Exh. JAP 46-CT at 17:16-19.

[327] Piliaris, Exh. JAP 46-CT at 21:1-10.

[328] PSE Initial Brief ¶ 69.

[329] *Id.*

[330] Staff Reply Brief ¶ 9.

bills.[331] Staff contends that its recommendation to exclude certain customers from the decoupling mechanism is consistent with the state's energy policy and actually promotes conservation by removing any disincentive to conserve.[332]

274 ICNU counters that PSE's assertion that exempting Schedule 46 and 49 customers from decoupling would "undermine the PCA settlement agreement" is simply wrong. ICNU points out that the PCA settlement agreement states that the "Settling Parties are not bound to any position with respect to the continuation of decoupling or the treatment of Fixed Production Costs within the decoupling mechanism in PSE's next general rate case."[333] ICNU asserts that PSE's position – that the PCA settlement precludes parties from proposing to exempt customers from decoupling because the settlement allows for the inclusion of fixed production costs in decoupling if the mechanism continues – is, in fact, the position that is contrary to that settlement.

275 Staff agrees with ICNU that proposals to remove some customers from decoupling are not a collateral attack on the settlement approved in Docket UE-130617. Staff cites to the relevant language in the PCA settlement, as follows:

> The Settling Parties are not bound to any position with respect to the continuation of decoupling or the treatment of Fixed Production Costs within the decoupling mechanism in PSE's next general rate case. However, if the electric decoupling mechanism continues for PSE after the review of decoupling in PSE's next general rate case, the electric decoupling mechanism will include Fixed Production Costs that were formerly tracked in the PCA mechanism …. Nothing in this Settlement binds any party to any position with regard to treatment of costs in an automatic escalation factor mechanism (such as a K-factor) or in a multi-year rate plan.[334]

Staff, in agreement with ICNU, interprets this language to mean that the Settling Parties are not obliged to take any particular position regarding the continuation of PSE's decoupling mechanism.[335] In addition, Staff argues that its interpretation is the only

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[331] Liu, Exh. JL-1CT at 36:6 - 38:6.

[332] Staff Reply Brief ¶ 9.

[333] ICNU Reply Brief ¶ 5 (citing Docket UE-130617, Order 11, App. A ¶ 9 (Mar. 27, 2015)).

[334] *WUTC v. Puget Sound Energy*, Docket UE-130617 (consolidated), Settlement Stipulation (March 27, 2015), ¶6.

[335] Staff Reply Brief ¶ 4.

sensible one because PSE's argument that no customer group can be removed from decoupling without violating the PCA Settlement would require the indefinite continuation of decoupling, while the continuation of the decoupling mechanism most definitely is an issue in this proceeding.

276 Concerning PSE's argument that proposals for removing customers from the decoupling mechanism are not fully developed, Staff observes that this is not a reason to reject the proposals. Staff relates that while natural gas Schedules 85, 85T, 87, and 87T were originally included in the decoupling mechanism (as of June 25, 2013), they were removed after reconsideration by the Commission (on December 12, 2013) after only six months.[336] At that time, PSE did not require specific guidance in how to exclude these schedules from decoupling.[337] Staff does not believe it would be difficult for PSE, with its expertise, to devise a reasonable procedure to remove certain schedules now, as it did when Schedules 85, 85T, 87, and 87T were removed from the decoupling mechanism.

Commission Determination

277 The parties' respective proposals to regroup rate schedules within the decoupling mechanisms are conceptually well grounded. Establishing greater homogeneity within groups will reduce the potential for cross subsidies and reduce rate volatility by better aligning customers with similar load profiles. How, exactly, we should regroup the electric and natural gas rate schedules turns in significant part on the question whether certain large non-residential customers should be removed from the decoupling mechanisms.

278 In general, we find that the concerns about fixed revenue erosion that motivate revenue decoupling proposals are a relevant concern for residential and small commercial customers but not for large industrial and commercial customers. While PSE recovers its fixed costs from residential customers through energy charges, raising the risk of fixed revenue erosion resulting from the implementation of energy efficiency programs, large non-residential customers operate under a rate structure that includes both a demand charge and an energy charge. Therefore, any fixed revenue erosion concerns associated with large non-residential customers can be addressed by ensuring that the majority, or even all, of fixed costs associated with serving large customers are recovered through

[336] Staff Initial Brief ¶ 71 (citing *See* 2013 PSE Decoupling Order at 93, ¶ 237; *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-121697, UG-121705, UE-130137, & UG-130138, Order 09, at 32, ¶ 77; 33, ¶ 80 (Dec. 12, 2013)).

[337] *Id.* (citing *See* 2013 PSE Reconsideration Order at 32, ¶ 77, 33, ¶ 80).

demand charges or customer charges, rather than energy charges that fluctuate with energy consumption.

279 This is a critical factor as we consider several parties' proposals to remove from decoupling, at the very least, electric Schedules 40,[338] 46, and 49. We consider at the same time Staff's proposal, supported by several parties, to remove from decoupling additional large non-residential customer schedules, including electric Schedules 12/26, 10/3 1, 29, 35, and Staff's proposal to remove natural gas Schedules 86/86T from decoupling.[339]

280 Ms. Liu's analysis shows generally that decoupling may not be well suited for large industrial and farm irrigation schedules with relatively few customers and a wide variation in usage.[340] Mr. Ball, Staff's witness for cost of service, rate spread, and rate design issues, conducted a detailed cost-of-service study and proposed a sizable increase in demand charges for Schedules 46 and 49 to address fixed cost recovery concerns due to these customers' declining usage per customer.[341] Another factor we must consider in this connection, however, is the Settling Parties' and Public Counsel's agreement to accept Staff's recommendation to include fixed production costs in the decoupling mechanism. This will approximately double the amount of fixed costs recovered through the decoupling mechanism.

281 By definition, fixed production costs would be recovered through decoupling only for the schedules for which decoupling will continue. For those schedules that Staff recommends discontinuing decoupling, fixed production costs of serving those schedules would be recovered, as proposed by Staff, through an updated or modified rate structure. Mr. Ball would address the fixed cost recovery concerns due to these customers' declining usage per customer through his detailed cost-of-service study and proposed 48 percent increase to demand charges for Schedules 46 and 49.[342] While we cannot be certain this modified rate structure will adequately protect PSE's recovery of fixed costs from Schedule 46 and

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[338] The Settlement Stipulation provides in ¶ 96 that Schedule 40 will be discontinued by the tariff effective date of PSE's next general rate case, and Schedule 40 will be closed to new customers effective as of September 15, 2017, the "Settlement Date." The Settlement Stipulation provides in ¶ 98 for a recalculation of allowed revenue per customer under the decoupling mechanism when Microsoft is removed from Schedule 40. Thus, the Settling Parties tacitly agreed to continue decoupling for this Schedule, pending its termination.

[339] Staff Initial Brief ¶ 69 (citing Liu, Exh. JL-1CT at 45:16-22).

[340] Liu, Exh. JL-1CT at 41:9-16.

[341] Ball, Exh. JLB-1T at 54:3-10.

[342] Ball, Exh. JLB-1T at 54:3-10.

48 customers, there is no evidence refuting this proposal. Further, the significant increase in demand charges seems more likely than not to protect the large non-residential customers better from rate volatility associated with decoupling and declining usage per customer.

282 PSE's arguments against proposals to remove Schedule 46 and 49 are not persuasive. We read the PCA settlement to mean that PSE would include as part of its litigation position in this rate case the inclusion of fixed production costs in the decoupling mechanism, but that the parties were free to oppose that proposal. What is more, the fixed production costs provisions of the PCA settlement are not prescriptive in terms of how fixed production costs would be included in the decoupling mechanism, if allowed by the Commission, or from whom they would be recovered under the decoupling tariff. Indeed, PSE abandoned its litigation position on this issue when it adopted, in part, Staff's position in the Settlement Stipulation in this case.

283 Second, PSE's rebuttal case, presented in Mr. Piliaris's testimony, largely rests on the argument that rejecting PSE's approach to fixed production cost would undermine the PCA settlement, which would have a chilling effect on future settlement negotiations. As we stated previously, the Commission does not share PSE's interpretation that the PCA settlement essentially guaranteed the move of fixed production costs into the decoupling mechanism in the manner PSE proposed, if at all. Moreover, it is not possible to reconcile PSE's argument here with its contradictory approach to the cost of service/rate design settlement in Docket UE-141368, which required the Company to include a declining third block rate in its residential rate design in this case. PSE did not include such a rate in its filing in this proceeding. PSE cannot choose whether or not to comply with the terms of settlements it reaches with other parties, and then argue that other parties are not following settlement terms.

284 In contrast to its proposal with respect to Schedules 46 and 49, going forward, Staff is not proposing at this time to restructure rates for electric Schedules 12/26, 10/31, 16, 29, 35, 43, or gas Schedules 86 and 86T. Ms. Liu testified that the rate structure approved in 2013 and currently in place for Schedule 12/26 and 10/31 customers "is sufficient to allow an opportunity for fixed cost recovery."[343] Demand charges were increased as a compromise between customers arguing for higher demand charges instead of a decoupling mechanism and PSE, which argued decoupling was necessary to produce stable revenue for the Company. Ms. Liu testified that "[t]he increased demand charges

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[343] Liu, Exh. JL-1CT at 42:16-18.

better aligned rate design with the underlying cost of service for these schedules and can serve as a model for decoupling other PSE non-residential electric rate classes."[344]

285 As to the remaining schedules, however, Ms. Liu testified they are "all unique in their own ways."[345] She said, moreover, that "it is difficult to predict revenue volatility from these schedules."[346] While Staff recommends excluding these electric and natural gas schedules from decoupling, this is coupled with a suggestion that PSE "monitor the usage pattern of these customers and assess whether the current rate structure for electric Schedules 29, 35, 43 and gas Schedules 86/86T needs to be improved."[347]

286 We are persuaded on the basis of the evidence and argument discussed above that we should approve the removal of Schedules 46 and 49 from PSE's electric decoupling mechanism. The Commission will have the opportunity over the next four years to monitor how successfully the increased demand charges, to which the Settling Parties agreed, serve to make decoupling unnecessary for these large non-residential customers.

287 With respect to the remaining electric rate schedules that Staff and other parties recommend for removal from decoupling, we think a more cautious approach is in order considering the significant increase in fixed costs recovery with the addition of fixed production costs to the decoupling mechanism. We do not order these schedules to be removed from the Company's decoupling mechanisms at this time. However, we expect PSE to continue monitoring closely the operation and results of decoupling mechanisms for all of its rate schedules and to examine the rate design of its non-residential rate schedules with an eye to improvements that may better serve the needs of customers and the Company. We expect to consider again within the next four years whether changes in rate design, such as what we authorize here with respect to Schedules 46 and 49, offer a superior alternative to decoupling for other non-residential electric customers.

288 As to Staff's proposal to remove certain non-residential natural gas rate schedules from decoupling (*i.e.*, Schedules 86 and 86 T), we are not persuaded that the small increases PSE proposes to demand charges for these customers would adequately support this

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[344] Liu, Exh. JL-1CT at 44:2-4.

[345] Liu, Exh. JL-1CT at 44:12.

[346] Liu, Exh. JL-1CT at 45:7.

[347] Liu, Exh. JL-1CT at 45:11-13.

result. Staff does not independently propose changes to demand charges for PSE's non-residential natural gas customers.

3. Other Decoupling Issues

289 Public Counsel witness Mr. Brosch testified that PSE's revenue-per-customer model of decoupling[348] should be replaced entirely with a "complete" decoupling model, which tracks all drivers of sales fluctuations in separate accounts.[349] Doing so, he argues, would address the "found margin" issue, discussed in both the Commission's Decoupling Policy Statement and in Order 07 that approved PSE's decoupling mechanism, and ensure that the decoupling mechanism nets the increased costs that PSE incurs from serving new customers against the increased revenue that it receives.[350]

290 Mr. Brosch testified that "[i]f the intent of decoupling is to completely break the link between sales volumes and utility revenues, all of the drivers of revenue change must be recognized."[351] The mechanism approved for PSE in 2013, he states, addresses changes in utility sales volumes caused by fluctuations in weather, changes in economic conditions and shifts in large commercial customer demand, and caused by systematic reductions in sales through time resulting from utility sponsored conservation programs, customers' conservation efforts, improvements in appliance efficiency, improved building standards, and the influx of distributed energy resources. He contends, however, that PSE's decoupling mechanisms do not account for fluctuations caused by systematic

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[348] We note that the Settling Parties agreed that the inclusion of fixed production costs in the decoupling mechanism should be based on a revenue per class model, as proposed in Ms. Liu's testimony. Settlement Stipulation ¶ 113; *see* Liu, Exh. JL-1CT at 53:10-54:11. Thus, going forward, only about one-half the costs recovered through the decoupling mechanism are implicated by Mr. Brosch's testimony.

[349] Brosch, Exh. MLB-1T at 35:10-17. The Energy Project, relying on Mr. Brosch's testimony, supports this recommendation. See Energy Project Initial Brief ¶¶ 30-32.

[350] Brosch, Exh. MLB-1T at 34:4-35:9. The Commission said in Order 07, approving the Rate Plan and decoupling, that in light of "the uncertain future, the Commission will wish to monitor carefully the actual results of customer growth in terms of earnings over the next several years and rely on the protection of the earnings test, as modified by this Order, that will keep any excess earnings that may be attributable in part to customer growth from becoming a windfall for PSE." *See supra* n.1 (Order 07-2013 Rate Plan ¶117).

[351] Brosch, Exh. MLB-1T at 30:1-2.

growth in sales through time caused by the continuous addition of new customers for PSE, which, he contends benefits from significant customer growth.[352]

291 PSE argues that the revenue-per-customer approach to decoupling approved by the Commission in 2013 has not resulted in "found margin."[353] The Commission recognized in the Decoupling Policy Statement, "revenue associated with new customers is offset by the costs to serve those customers."[75] In other words, there is "margin" only if incremental revenue exceeds incremental costs. PSE demonstrated through the testimony of Ms. Barnard and Mr. Piliaris that the cost of serving new customers exceeds the revenue generated from the new customers by 1.2 percent per year. It follows, PSE argues, that there is no found margin.[354]

292 PSE argues further that "Public Counsel and The Energy Project consider only the incremental revenue and ignore the incremental costs associated with new customers."[355] Citing Mr. Piliaris' testimony concerning line transformer costs and overhead administrative costs,[356] PSE says the Company has demonstrated that Public Counsel's claim that most "fixed costs do not vary with the number of customers served" is incorrect.[357] PSE points also to Ms. Liu's testimony that revenue-per-customer decoupling is based on the assumption that there is cost associated with serving each additional customer and that the allowed revenue should follow the cost.[358] Ms. Liu explains that:

> There is a correlation between delivery costs and the number of customers. Typically, the Company will need to invest in lines and feeder plant to serve customers in a new development. The Company will also incur costs (*e.g.*, line maintenance, customer service, general administrative costs) to serve the additional customers.[359]

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[352] Brosch, Exh. MLB-1T at 30:3-11.

[353] PSE Reply Brief ¶ 21.

[354] *See* Barnard, Exh. KJB-1T at 6:10-11; Piliaris, Exh. JAP-46CT at 23:9-14.

[355] PSE Reply Brief ¶ 22.

[356] *See* Piliaris, Exh. JAP-46CT at 44:8 – 49:3 (line transformer costs), 50:10 – 51:13 (overhead administrative costs).

[357] PSE Reply Brief ¶ 22.

[358] Liu, Exh. JL-1CT at 49:12-15.

[359] Liu, Exh. JL-1CT at 49:15-19.

Citing Ms. Barnard's testimony, Ms. Liu says PSE's "operating expense increased at a growth rate of 2.0 percent between 2011 and June 2016, outstripping the customer count growth rate of 0.8 percent."[360] Ms. Liu concludes that "the Revenue per Customer approach [adopted in 2013] works well when the delivery costs and customer counts both trend upwards."

293 Ms. Liu undercuts The Energy Project's implied argument that the Commission should now abandon revenue-per-customer decoupling entirely based on the fact that "PSE and other parties effectively agreed to use Public Counsel's alternative approach in the case of fixed production costs."[361] The Settling Parties agreed that the inclusion of fixed production costs in the decoupling mechanism should be based on a revenue per class model, as proposed in Ms. Liu's testimony, not a revenue per customer model.[362] Thus, going forward, only about one-half the costs recovered through the decoupling mechanism are implicated by Mr. Brosch's testimony. Ms. Liu testified that in contrast to the correlation between delivery costs and the customer counts:

> Such a correlation does not exist between fixed production costs and customer counts. When the Company needs to serve increased load due to customer growth, it has the choice of whether to build new generation plants or buy power from the market. But a bigger customer base, or higher load, does not necessarily mean higher fixed production costs. Fixed production costs, at best, increase in big steps, when the load demand grows over a long time period, as shown in my trend analysis in Exh. JL-7C.[363]

Commission Determination

294 We are persuaded by the evidence discussed above that the Commission's approach to decoupling, going forward, should continue to use a revenue-per-customer approach for most costs and a revenue-per-class approach for fixed production costs. We reject the "complete decoupling" approach advocated by Public Counsel and The Energy Project because it fails to take into account all relevant factors and ignores salient facts, as discussed above.

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[360] Liu, Exh. JL-1CT at 49:19-21 (citing Barnard, Exh. KJB-1T at 7:10-11).

[361] Energy Project Initial Brief ¶ 32.

[362] Settlement Stipulation ¶ 113; *see* Liu, Exh. JL-1CT at 53:10-54:11.

[363] Liu, Exh. JL-1CT at 50:3-9.

4. Proposed changes to the soft cap, the earnings sharing test, and the earnings sharing mechanism (*i.e.*, establishing a 25 basis point deadband for earnings sharing)

a. Rate Cap

295 The decoupling mechanism's 3 percent annual rate cap means that in some years, PSE's unrecovered costs may need to be deferred by more than a year. Mr. Piliaris stated that costs deferred beyond a year create an earnings challenge for PSE because Generally Accepted Accounting Practice (GAAP) requires revenues to be recovered within 24 months to be counted as current-year revenue.

296 PSE proposes two changes to the rate cap, which it refers to as the Rate Test. First, PSE proposes to use weather-normalized billing determinants when testing whether the Company exceeded its authorized decoupling revenue. Second, PSE proposes to increase the soft cap from 3 to 5 percent for residential natural gas customers and all electric customers "in response to concerns about growing deferral balances expressed by the Commission at annual Schedule 142 filings."[364]

297 PSE argues that the Company's proposal to change the Rate Test calculation will make it more simple and transparent, while increasing the soft cap will address the issue of large deferrals on the gas side and allow greater flexibility on the electric side if fixed production costs are included. In support of its proposed soft cap increase, PSE provides analysis demonstrating that had fixed production costs been included in the original decoupling mechanism, the Company would have exceeded the 3 percent cap in 2015.[365] PSE also argues that a 5 percent cap is aligned with Pacific Power's mechanism and, as Staff stated, would simplify the mechanism's operation.[366] Finally, PSE argues that its proposal is supported by the recommendations in the Gil Peach Report[367] and analysis PSE has performed showing that the decoupling-related gas residential deferrals would

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[364] PSE Initial Brief ¶ 78.

[365] Piliaris, Exh. JAP-46 CT at 13:10.

[366] Piliaris, Exh. JAP-46 CT at 13:16-14:2.

[367] *See* Piliaris, Exh. JAP-29 at 132 ("We recommend that the Rate Test be adjusted from a 3% soft cap to a 5% soft cap to clear balances in most years while still providing a level of protection to the customer against extreme rate changes. As discussed earlier in this section, the benefit of raising the soft cap from 3% to 5% on rate increases includes better temporal alignment between incurred cost of service and the actual payment for service. This benefits both the customer class and PSE.").

have cleared if a 5 percent cap on rate increases had been in place in the 2015 and 2016 annual filings, rather than the 3 percent cap.[368]

298 PSE's rationale for increasing the soft cap for electric rates reflects that a greater amount of electric revenues would be subject to decoupling under the terms of the PCA Settlement, which provides that fixed production costs will be included in PSE's electric decoupling mechanism.[369]

299 Mr. Brosch testifies against PSE's proposed changes to the soft cap, stating that the limited unamortized balances the Company has recorded are justified by the protections that the test offers customers.[370] He also opposes the proposed changes to the earnings test – the removal of normalizing adjustments and the establishment of a dead band – arguing that the test provides an important safeguard against excess earnings that could result from the decoupling mechanism.[371]

300 Ms. Levin, testifying for NWEC/RNW/NRDC, accepts the Company's proposal to increase the rate cap to 5 percent for residential gas customers only, based on the large deferrals that exist, but recommends that the Commission only do so temporarily, and directs PSE to improve its weather forecasting model.[372] NWEC/RNW/NRDC opposes the proposed rate cap increase for electric customers, arguing that PSE has not demonstrated any harm arising from the current cap.[373]

301 Mr. Collins, testifying for The Energy Project, expresses concern with PSE's proposal to increase the rate cap, given the impacts that the decoupling mechanism has had on low-income customers under the existing 3 percent cap.[374] He states that decoupling has resulted in annual bill increases of more than $100 for customers receiving bill assistance, representing about 25 percent of the $409 average HELP grant that those customers received in 2016.[375] These increases have come at a time when federal energy assistance

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[368] *See* Piliaris, Exh. JAP-1T at 135:13-17.

[369] PSE Initial Brief ¶ 80 (citing *See* Settlement Agreement ¶ 113).

[370] Brosch, Exh. MLB-1T at 46:7-21.

[371] *Id.*, 48:15-20.

[372] Levin, Exh. AML-1T at 24:1-25:5.

[373] Levin, Exh. AML-1T at 25:21-26:1.

[374] Collins, Exh. SMC-1T at 27:8-18.

[375] Collins, Exh. SMC-1T at 25:9-13.

funding has been decreasing at a rate faster than PSE has increased its program funding.[376]

Commission Determination

302 PSE's proposal to increase the soft cap for the electric decoupling mechanism from 3 percent to 5 percent is unsupported by any evidence of financial harm to PSE or customers from the current 3 percent cap. PSE argues that deferral balances may grow on the electric side if fixed production costs are included but this is simply speculation and in that sense PSE's proposal is a solution in search of a problem. If such a problem does develop over time, we can revisit this issue with respect to the electric decoupling mechanism.

303 In contrast to electric decoupling results, large deferrals have developed under the natural gas decoupling mechanism with unrecovered balances remaining on PSE's books for more than one year. Because this creates an earnings challenge for PSE considering that GAAP requires revenues to be recovered within 24 months to be counted as current-year revenue, we find it appropriate to increase the soft cap for natural gas decoupling to 5 percent. The Commission will revisit this issue during its next review of the Company's decoupling mechanisms, no later than four years after the date of this Order

b. Earnings Sharing

304 When determining its overall earnings performance for the purpose of sharing excess earnings with customers under the current mechanism, PSE is required to apply normalizing adjustments that the Company argues distort its earnings and result in inaccurate outcomes. PSE proposes to remove the normalizing adjustments from the earnings test so that any earnings sharing is based on the Company's actual financial performance. The Company also proposes a 25 basis point dead band on the earnings test and to share earnings with customers based on each class' allocated revenues rather than volumetric revenues.

305 Staff opposes the Company's proposed changes to the earnings test, arguing that normalizing adjustments are important because they were used in the rate case that established the authorized revenue requirement, and should therefore be used when evaluating the utility's performance relative to that baseline.[377] Staff opposes the

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[376] Collins, Exh. SMC-1T at 25:13-17.

[377] Liu, Exh. JL-1CT at 58:18-59:11.

Company's proposed dead band for the earnings test on the grounds that the Company's authorized rate of return has been established to adequately compensate it for the risks it faces.[378]

306 Public Counsel witness Mr. Brosch also opposes the proposed changes to the earnings test – the removal of normalizing adjustments and the establishment of a dead band – arguing that the test provides an important safeguard against excess earnings that could result from the decoupling mechanism.[379]

307 Kroger witness Mr. Higgins opposes PSE's proposal to place a dead band on the earnings test because the decoupling mechanism transfers risk from the Company to ratepayers, and the dead band would further transfer risk. He argues, too, that the test should be asymmetrical, given the asymmetrical transfer of risk that decoupling instituted.[380] Finally, he concludes PSE's proposal to increase the rate cap should be rejected. However, these positions were stated prior to Kroger's position on settlement.[381]

Commission Determinations

308 We find the Company's testimony and evidence persuasive in support of removing the normalizing adjustment from the earnings test. The Commission Basis Reports (CBR) that PSE files annually with the Commission, provide both the actual and normalized results. These reports form the basis for the earnings test under the decoupling mechanism. Any party wishing to analyze the Company's performance may do so based on either result, thereby undermining Staff's argument that it would not be able to evaluate the utility's performance relative to the normalized baseline.

309 We find it is not appropriate for the earnings sharing mechanism to require the Company to share revenues based on "theoretical" earnings. To illustrate, in the event of a warm Pacific Northwest winter, PSE likely would not be able to earn its authorized rate of return even with the revenues captured through the annual decoupling mechanism true-up filing. However, because the current process requires the sharing to be based on a "normal" winter, these normalizing adjustments may result in a CBR filing reflecting increased normalized net operating income leading to earnings in excess of the authorized

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[378] Liu, Exh. JL-1CT at 60:4-9.

[379] *Id.*, 48:15-20.

[380] Higgins, Exh. KCH-1T at 16:15-21.

[381] Higgins, Exh. KCH-1T at 17:11-15.

rate of return. The Company would then be required to share revenues with ratepayers that it never received from ratepayers.

310 Conversely, the opposite scenario is unfair to ratepayers. In the event of a colder than normal winter, the Company may actually realize revenues in excess of its authorized rate of return. However, due to the normalizing adjustments for the earnings sharing mechanism, the Company potentially would not share any of those overearnings with ratepayers.

311 Further, we acknowledge that the central purpose of decoupling mechanisms is to reduce the "throughput incentive," which is at odds with the objectives of energy efficiency programs. In our two weather scenarios above, the earnings sharing mechanism based on normalized conditions works against minimization of the throughput incentive. Thus, following these scenarios, the Company might relax its conservation efforts.

312 On the other hand, we are not convinced that PSE's proposal for a 25 basis point dead band for the earnings test would result in fair, just, and reasonable rates. We agree with Staff that if we were to authorize an earnings sharing dead band of 25 basis points, we would be authorizing a higher rate of return than deemed appropriate from the cost of capital evidence in the record of this proceeding. While we agree that the earnings mechanism should be based on actual, not theoretical earnings, allowing an additional 25 basis points could transfer risk inappropriately from the Company to ratepayers.

313 We approve the Company's proposal to remove normalizing adjustments from the earnings test, but reject the 25 basis point deadband.

B. Electric Cost Recovery Mechanism

314 PSE proposes that the Commission establish an electric cost recovery mechanism (ECRM) modeled, to a significant degree, after its natural gas pipeline cost recovery mechanism (GCRM), which the Commission approved in 2013. Ms. Gilbertson described the Company's reliability challenges that prompted its request for the ECRM. Ms. Koch testified concerning the Company's approach to identifying needs and its proposed investment plan. Ms. Barnard presented an overview of the Company's proposed filings and calculation of rates. Mr. Piliaris summarized the Company's proposed method of allocating costs incurred through the ECRM. Mr. Doyle and Ms. Barnard defended the Company's proposal on rebuttal.

315 Ms. Barnard stated that the ECRM would allow the Company to "accelerate the replacement of targeted reliability improvements intended to reduce the number and length of outages" and recover their costs between rate cases.[382] She discussed that PSE's proposed mechanism is closely patterned after the natural gas pipeline cost recovery mechanism that the Commission established for pipeline replacement in Docket UG-120715,[383] with minor changes to the timing of filings[384] and the cost allocation method.[385]

316 Ms. Koch stated that the Company's two primary goals for the ECRM are to improve its worst-performing circuits and to replace aging underground cable that is at risk of failing.[386] The Company's requested first-year revenue requirement is $10.5 million.[387]

317 Staff, Public Counsel, ICNU, and Kroger all actively oppose the Company's proposal. No party filed testimony in support of it.

318 Staff witness Mr. Schooley argued that patterning the ECRM after the pipeline cost recovery mechanism is inappropriate because the gas mechanism was designed to address a safety issue, while the ECRM is proposed to address a reliability issue – two very different goals.[388] Mr. Schooley also opposed the ECRM on the grounds that it would result in pre-approval of investments, that the Commission is evaluating distribution planning in the ongoing Integrated Resource Planning (IRP) rulemaking, and that PSE should not need a mechanism as an incentive to meet its obligation to provide safe and reliable service.[389]

319 Public Counsel witness Mr. Brosch echoed Staff's argument that PSE does not need additional incentives to engage in prudent investment planning for its distribution system.[390] He also argued that such planning should remain in the purview of the utility, as other parties do not have enough information to provide meaningful review and

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[382] Barnard, Exh. KJB-1T at 73:14-20.

[383] Barnard, Exh. KJB-1T at 73:20-74:2.

[384] Barnard, Exh. KJB-1T at 77:1-78:6.

[385] Piliaris, Exh. JAP-1T at 148:1-13.

[386] Koch, Exh. CAK-1CT at 4:7-10.

[387] Barnard, Exh. KJB-1T at 81:2.

[388] Schooley, Exh. TES-1T at 26:15-17.

[389] *Id.*, 27:9-28:6.

[390] Brosch, Exh. MLB-1T at 55:22-23.

feedback.[391] Public Counsel witness Ms. Alexander also testified against the ECRM, arguing that a mechanism developed for natural gas safety is not applicable to electric reliability and that the proposal lacks specific metrics for measuring its success.[392]

320 ICNU witness Mr. Gorman argued that riders like the proposed ECRM are only appropriate for costs that are volatile and outside the utility's control, which is not the case with planned distribution system investments.[393]

321 Kroger witness Mr. Higgins opposed the mechanism because, he argued, it would constitute single-issue ratemaking and its costs should be allocated on a demand basis, not an energy basis, as proposed by the Company.[394]

322 On rebuttal, PSE witness Mr. Doyle outlined the Company's defenses of the ECRM: that PSE's projected $78 million in investments for distribution reliability improvement in 2017 will be subject to significant regulatory lag absent the mechanism;[395] that the ECRM will reduce the need for frequent rate filings;[396] and that it will spread cost recovery across smaller, more predictable increases, rather than large, lump sum increases.[397] He testified, too, that the ECRM is comparable to trackers for other programs with large, predictable expenditures, such as the Company's conservation rider.[398]

323 Ms. Barnard elaborated in her rebuttal testimony that absent the ECRM, the Company would face regulatory lag of 27 months, which would result in "significant earnings erosion" when applied to the level of investment contemplated in the Company's proposal.[399] She stated that PSE crafted the ECRM in response to the Commission's rejection of distribution investments in recent Avista rate cases – arguing that PSE's

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[391] *Id.*, 54:17-55:16.

[392] Alexander, Exh. BRA-1T at 31:9-33:12.

[393] Gorman, Exh. MPG-1T at 43:16-23.

[394] Higgins, Exh. KCH-1T at 22:9-23:2.

[395] Doyle, Exh. DAD-7T at 23:11-24:2.

[396] *Id.*, 24:3-5.

[397] *Id.*, 24:6-11.

[398] *Id.*, 24:12-25:8.

[399] Barnard, Exh. KJB-17T at 100:3-11.

testimony regarding both the need for the investments and a targeted approach to making them address the analytical faults that the Commission identified in those cases.[400]

324 Ms. Koch defended the Company's comparison between the ECRM and the gas recovery mechanism, arguing in her rebuttal testimony that the gas mechanism has provided PSE with a successful template for the ECRM. She testified that reliability is a key utility function that is deserving of the same targeted approach that characterizes the GCRM.[401]

325 Mr. Piliaris agreed with Kroger that if the ECRM is approved, its costs should be collected through demand charges from schedules that have that component.[402]

Commission Determinations

326 PSE presents an interesting argument – that absent some mechanism for prioritizing or better valuing distribution reliability investments, those investments may not be funded in the highly competitive capital budgeting process. That said, Ms. Barnard's representation that the Company would face 27 months of regulatory lag is an exaggerated, worst-case scenario that assumes average of monthly averages (AMA) treatment for the investments, while failing to consider other tools the Commission has adopted for attenuating regulatory lag, such as end-of-period rate base and pro forma adjustments.

327 Further, we are not persuaded that PSE is unable to prioritize in its capital budgeting process funding to address the worst-performing circuits and to replace aging underground cable that is at risk of failing. PSE has not demonstrated any efforts to review that process to reprioritize projects to secure funding for these specific projects.

328 Though PSE's proposal may have some merit, it is not yet timely. As Mr. Schooley points out, the Commission is considering distribution planning requirements in the IRP rulemaking. That process is exploring how utilities, Staff and other stakeholders might collaborate on distribution plans that identify needs and cost-effective solutions to a wide range of challenges, not just reliability concerns. It may be appropriate to build a framework for distribution planning before adopting a mechanism that depends on distribution planning.

329 We determine that the Commission should not approve PSE's proposed ECRM.

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[400] *Id.*, 101:3-102:6.

[401] *Id.*, 11:10-12:13.

[402] Piliaris, Exh. JAP-46CT at 66:8-16.

C. Cost of Service, Rate Spread, and Rate Design

330 Cost of service studies identify the costs incurred to provide service to each class of customers, and inform a balanced allocation (*i.e.,* rate spread) of the electric and natural gas revenue requirements among customers. Perspectives on how best to perform cost of service studies vary widely, leading to a broad range of possible results. Much of the disparity among the various cost of service studies in the record can be traced to the fact that it has been decades since the Commission has analyzed comprehensively, or in any depth, the principles that should be used in developing cost of service studies.[403]

331 In this case, the parties queued up for decision quite a number of issues related to cost of service, rate spread, and rate design. A few of these issues are addressed in the Settlement Stipulation, discussed above, but many remain in dispute. There is at least a consensus, however, that we should resolve these issues only for purposes of this case. PSE, Staff, and NWIGU all urge us to defer more enduring policy decisions concerning methodologies and their application to ongoing generic proceedings initiated in January of this year.[404]

332 We agree that the Commission should limit the application of its decisions on the contested issues discussed below to this case and allow the ongoing generic proceedings to continue. This not only is a sensible approach, it is a necessary approach given the less than fully developed state of the record on these issues in this proceeding.

1. Electric Cost of Service Study, Rate Spread, and Rate Design

333 PSE developed its Electric Cost of Service (COS) Study for this case as provided by the Commission-approved settlement resulting from the 2014 Electric Cost of Service and Rate Design Collaborative (Rate Design Settlement).[405] The Company proposed, however, to update the data used in the peak credit method that allocates generation and transmission fixed costs with information from the Company's 2015 and 2017 Integrated

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[403] Without reviewing every final order entered in a utility general rate case over the past two decades to find any exceptions, it is fair to observe that cost of service, rate spread, and most rate design issues have been resolved among the parties to individual cases by negotiation and settlement. Most often the result has been to maintain the status quo from one case to another.

[404] The Commission initiated electric Docket UE-170002 and natural gas Docket UG-170003 on January 3, 2017. *See* PSE Initial Brief ¶ 6; Staff Initial Brief ¶¶ 4-5; NWIGU Initial Brief ¶¶ 3, 12.

[405] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket UE-141368 (Jan. 29, 2015).

Resource Plans and uses the Company's proposed rate of return.[406] These proposed updates changed the demand/energy allocation ratio from 25 percent demand and 75 percent energy to 18 percent demand and 82 percent energy.

334 Mr. Ball testified that Staff agreed with these changes in principle because the Rate Design Settlement used information that will be three to five years old by the end of this proceeding.[407] Mr. Ball stated that using more current information was a primary objective of the Rate Design Settlement and doing so will provide a cost of service study that is more reflective of the present day costs to serve customers.[408] Finally, Mr. Ball testified that while he did not challenge the Company's COS methodology, he did prepare a version of the COS study that shows the effect of Staff's rate design proposal and incorporates Staff's revenue requirement results.[409]

335 FEA argued that the Commission should enforce the terms of the Rate Design Settlement in Docket UE-141368 based on its plain terms and meaning, not based on PSE's interpretation of the "spirit" of the settlement.[410] Mr. Al-Jabir testified for FEA that the settlement agreement in Docket UE-141368 explicitly requires that the demand and energy classification percentages be set at 25 percent demand and 75 percent energy in this proceeding.[411] FEA argues that fairness and the importance of strictly enforcing the plain terms of a Commission-approved settlement require that the Commission reject PSE's proposed change to update the demand/energy allocation ratio.

Commission Determination

336 We agree with FEA that the Commission should enforce the terms of the Rate Design Settlement in Docket UE-141368 based on its plain terms and meaning. The settlement agreement explicitly requires that the demand and energy classification percentages be set at 25 percent demand and 75 percent energy in this proceeding. We enforce that term as written.

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[406] Piliaris, Exh. No. JAP-1T at 27:17-28:2.

[407] Ball, Exh. JLB-1T at 8:228-33.

[408] Ball, Exh. JLB-1T at 8:228-33.

[409] Ball, Exh. JLB-1T at 8:235-40 (with reference to Exh. JLB-2).

[410] FEA Initial Brief at 8.

[411] FEA Initial Brief at 8.

337 We emphasize the importance of strictly enforcing the plain terms of Commission-approved settlements.[412] The parties in this proceeding are familiar with the Commission's processes and procedural rules that require any departure from the terms of a Commission-approved settlement be supported by a Commission order amending the settlement. Amendments typically are proposed by a motion from one or more parties. Unless such a motion is joined by all parties, non-moving parties can answer and avail themselves of their rights to due process. Even when all parties agree to a motion to amend, the Commission has the opportunity to consider whether it should grant the motion.

a. Electric Rate Spread

338 The Settling Parties agreed to resolve rate spread and rate design issues for PSE's electric operations addressing six principal areas. Specifically, the Settling Parties agreed that:

- Schedules 7A, 11, 25, and 29 (General Service, 51 – 350 kW) and Schedules 12 and 26 (General Service, >350 kW), all of which are at 108 percent of parity; and Schedules 10 and 31 (Primary Service, Gen & Irr.) and Schedules 46 and 49

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[412] We note in this connection that we have an instance in this case of a party, PSE, not adhering to the terms of the settlement stipulation without first obtaining a Commission order authorizing a departure from the terms of the agreement. The settlement in Docket UE-141368 required PSE to propose a residential rate design that included "a third block using an inverted rate structure" with cutoffs for the second and third block at 800 kWh and 1800 kWh, respectively. PSE, however, did not propose such a rate structure. Mr. Piliaris testified that the Company attempted to design a third block based on the assumption that it should be set equal to the Company's estimated long-run avoided costs, but that it resulted in a third block that was lower than the first two blocks. Piliaris, Exh. JAP-1T at 58:19-60:3. As a result, the Company retained its two-block structure. That it was entirely possible for PSE to design and propose a third block rate using an inverted rate structure is shown by the fact that Staff witness Ball included such a proposal in his testimony. *See* Ball, Exh. JLB-6. After this case was docketed and its testimony filed with the Commission, PSE, jointly with Staff, Public Counsel, and The Energy Project filed an unopposed motion seeking to amend Order 03 in Docket UE-141368 to strike the language addressing a third block rate, including the requirement that PSE file such a rate in this case. Not only was this filing untimely, it also misrepresented that "PSE proposed such rates in its 2017 general rate case filing" when, in point of fact, it did not. Thus, we have PSE's violation of a Commission order compounded by a material misrepresentation in a motion joined by four parties. Because we resolve PSE electric rate design in this Order, we find the pending motion in Docket UE-141368 to be moot. We will refrain from taking any further action with respect to this matter, but we caution against any repeat of such inappropriate interaction with the Commission in the future.

(High Voltage), all of which are at 109 percent of parity, [413] will be moved closer to parity (*i.e.*, 107 percent of parity) by allocating to them 65 percent, rather than 75 percent, of the average rate increase.[414]

- For Schedule 25 customers, such as Kroger, which advocated the changes, the current tail block energy rate will be maintained, the basic charge will be increased, and demand charges will be increased.[415]
- Staff's proposal to begin phasing out Schedule 40 will be implemented.[416]
- Staff's proposal to increase demand charges for Schedules 46 and 49 will be implemented.[417]
- The allowed revenue-per-customer figures will be recalculated for other customers subject to decoupling when Microsoft leaves PSE's system.[418]
- The Ardmore Substation costs will be subject to a one-time adjustment that preserves each party's right to argue for allocating Ardmore Substation costs differently in future proceedings.[419]

339 There was little, if any, controversy concerning the fundamental importance of rate spread adjustments being grounded in principles of cost causation. The Settling Parties agreed to move modestly in the direction of achieving greater parity in non-residential rates with parity ratios greater than 1.0 while recognizing the importance of gradualism and rate stability to all customer classes.

340 Public Counsel notes in its Initial Brief that it does not address the non-residential electric rate design terms in Paragraphs 95, 97, and 99 of the Settlement.[420] Public Counsel takes no position with respect to Paragraph 98. In addition, Public Counsel affirmatively

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[413] We note that Schedules 8 and 24 also are at 109 percent of parity. However, a 75 percent allocation of the average rate increase results in these customers being at 107 percent of parity. *See* Ball, Exh. JLB-1T at 15:1 Table 2.

[414] Settlement Stipulation ¶ 94.

[415] Settlement Stipulation ¶ 95.

[416] Settlement Stipulation ¶ 96.

[417] Settlement Stipulation ¶ 97.

[418] Settlement Stipulation ¶ 98.

[419] Settlement Stipulation ¶ 99.

[420] Public Counsel Initial Brief ¶ 82 n141.

supports the Settlement Stipulation's provision in Paragraph 96 providing for the discontinuance of Schedule 40.[421]

341 PSE proposed that retail schedules within 5 percent of full parity, plus or minus, would receive the adjusted average rate increase. While PSE disagreed with the results of Public Counsel's cost of service study on which its parity ratios are set, PSE did not object to the use of a 10 percent deadband as proposed by Public Counsel,[422] which would result in most schedules not otherwise addressed in the Settlement Stipulation, including Residential (Schedule 7), Small General Service-4 Secondary (Schedule 24), Campus Rate (Schedule 40), All Electric Schools (Schedule 43) receiving an adjusted average rate increase.[423] Additionally, PSE agreed to Public Counsel's proposal to give Schedule 35 a rate increase that is 150 percent of the average because Schedule 35 has a parity ratio well below 1.0 using PSE's cost of service study.[424] PSE proposes that all other schedules not included in the Settlement Agreement, including Schedule 449, should receive the adjusted average rate increase.

342 PSE recommended that the Commission reject Public Counsel's proposal to give Schedule 449 customers a rate increase equal to 150 percent of the average.[425] PSE argued that the vast majority of the revenues associated with Schedule 449 are not subject to the Commission's jurisdiction but, rather, are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC), pursuant to PSE's Open Access Transmission Tariff (OATT). PSE argued that Public Counsel's proposal would effectively subject an otherwise FERC jurisdictional customer to Commission-based rates.[426]

Commission Determination

343 With respect to the only disputed issue here, we find that PSE is correct to oppose Public Counsel's proposed 150 percent increase for Schedule 449 because most of the revenues associated with this rate schedule are FERC jurisdictional and subject to PSE's OATT. Because the Settlement Stipulation's remaining issues and PSE's proposed resolutions of

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[421] Public Counsel Initial Brief ¶ 90.

[422] *See* Public Counsel Initial Brief ¶ 86.

[423] Piliaris, Exh. JAP-46CT at 37:12-38:1.

[424] *Id.* at 38:1-3.

[425] *See* Public Counsel Initial Brief ¶ 87.

[426] Piliaris, Exh. JAP-46CT at 38:6-39:2.

issues not fully addressed in the Settlement Stipulation are uncontested and supported by the record, we find PSE's electric rate spread should be approved as described above.

b. Fully Contested Rate Design Issues: Residential Rates

i. Basic Charge, Minimum Bill, Seasonal Rates

344 PSE proposed to increase its basic charge for single-phase electric service to $9.00 per month. Mr. Piliaris testified that this reflects the current level of costs traditionally recovered through the Company's residential electric basic charges, including customer service, customer accounting, meter reading, billing, plus the costs of line transformers.[427] This would result in a $1.51 per month increase over current rates.

345 Mr. Piliaris stated that "the proposed increase is reasonable for several reasons"[428]:

- PSE currently is collecting $0.38 per month of that amount through Schedule 141 (Expedited Rate Filing), which will be zeroed out in prospective rates effective after this general rate case, leaving a net impact on customer bills of $1.13 per month.[429]
- PSE's current overall residential basic monthly charge of $7.87 is based on a test year ending June 2012 and costs have grown since then.
- PSE's electric cost of service study in this filing supports a basic charge over $2 per month higher than the $9.00 being proposed in this filing.
- Had the 3 percent annual increases allowed under the Rate Plan been applied to basic charges, where the underlying costs are usually recovered, instead of being recovered through volumetric rates under the Rate Plan (a compromise reached in support of decoupling approval) the basic charge in effect in 2017 would have been $9.12 per month.[430]

346 Mr. Piliaris also reviewed the basic charges of national and local investor-owned electric utilities, and government and customer-owned utilities in Washington state and determined a national average of $9.17 for basic charges. Based on this review, he

[427] Piliaris, Exh. JAP-1T at 66:8-13.

[428] Piliaris, Exh. JAP-1T at 66:15.

[429] Piliaris, Exh. JAP-1T at 66:16-67:2.

[430] Piliaris, Exh. JAP-1T at 67:9-17.

determined that the average basic charge of the Washington utilities he surveyed is $17.76, "or almost double the basic charge being proposed by PSE in this filing."[431]

347 Staff proposed that the Commission establish a higher basic charge and a minimum bill with a seasonal rate two-block structure for both summer (April – September) and winter (October – March).[432] Mr. Ball testified that a minimum bill ensures that all customers contribute their full share of customer costs, while maintaining enough flexibility in energy rates to send appropriate economic signals in support of conservation.[433] Staff's identified customer cost of $10.88 includes line transformers, which Mr. Ball argues is appropriate given his analysis that establishes a strong correlation between customer count and transformer plant balances.[434]

348 Staff argues that seasonal rates are more appropriate than higher marginal rates because customers do not have enough information at a point in time to make informed decisions based on which price tier they are facing. Rather, Staff argues, customers respond to overall bills, and seasonal rates will send an intelligible price signal to customers that corresponds with the Company's higher power costs in the higher-demand winter months.[435] Mr. Ball provides detailed analysis in support of the seasonal rate calculation in Exh. JLB-4 and various analyses gaging the impact of seasonal rates on different customers.[436]

349 PSE argues that Commission Staff's proposal is too confusing and that the costs of implementing it outweigh the benefits. PSE estimates the additional $300,000 in revenue that is likely to result from the minimum bill, over and above what PSE would have recovered from the same customers without a minimum bill through volumetric rates, does not outweigh the confusion customers are likely to experience or the cost that PSE would incur in adding a minimum bill component into its residential rate structure.[437]

350 Mr. Watkins, testifying for Public Counsel, contends that three of Mr. Piliaris' four justifications for increasing the basic charge have little merit because they simply "relate to

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[431] Piliaris, Exh. JAP-1T at 68:1-12.

[432] Staff Initial Brief ¶ 32.

[433] Ball, Exh. JLB-1T at 37:8-43:11.

[434] Ball, Exh. JLB-1T at 26:1-28:10.

[435] Ball, Exh. JLB-1T at 33:1-34:3.

[436] Ball, Exh. JLB-1T at 37:8-43:11.

[437] *See* Piliaris, Exh. JAP-46CT at 42:1-44-7.

the time elapsed between the last rate case and the effects of various settlements," which are negotiated amounts that may, or may not, reflect the costs that should be included in the basic charge.[438] Mr. Watkins disputes Mr. Piliaris's cost justification, purportedly supporting a basic charge of $11.24 per month, because his "analysis inappropriately includes many costs that should not be deemed customer-related for purposes of evaluating the reasonableness of residential customer charges."[439]

351 Mr. Watkins identifies specific capital costs that Mr. Piliaris included in his customer cost analysis, including gross plant investments "in Meters ($88.5 million), Services ($175.6 million), Distribution Line Transformers ($333.2 million), and an allocated portion of General plant ($74.3 million)"[440] as being either otherwise accounted for in customer connection fees, contrary to accepted industry standards and practice, or overhead costs that should not be considered in a customer cost analysis.[441] Mr. Watkins also identifies operations and maintenance costs that he argues should not be included because they are "more appropriately considered demand-related (*e.g.,* transformer expenses) or are general overhead expenses required in order to sell electricity."[442] He acknowledged, however, that certain other Meter Reading and Customer Records & Collections expenses are properly included in Mr. Piliaris's customer cost analysis.

352 Mr. Watkins testifies that he conducted a "direct customer cost analysis," taking guidance from the Commission's treatment of this issue in Pacific Power's 2014-15 general rate case, calculating the direct residential customer cost with and without the inclusion of services cost, and under current and Company-proposed depreciation rates. He also used the Company's proposed cost of capital in this case (*i.e.*, 7.74 percent). Mr. Watkins's analysis produced a direct residential customer cost between $4.05 and $5.61 per month at the Company's requested rate of return. He proposed on this basis, and for policy reasons related to price signals and conservation, to essentially retain PSE's current $7.49 customer charge, suggesting that for purposes of "a more logical rate" the charge should be rounded up by one cent, to $7.50 per month.[443]

353 Mr. Shawn Collins testified for The Energy Project that PSE's proposal to raise the residential electric basic monthly charge to $9.00 makes an essential service "less

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[438] Watkins, Exh. GAW-1T at 42:12-43:2.

[439] Watkins, Exh. GAW-1T at 43:5-12.

[440] Watkins, Exh. GAW-1T at 43:15-17.

[441] Watkins, Exh. GAW-1T at 43:18-54-5.

[442] Watkins, Exh. GAW-1T at 46:4-9.

[443] Watkins, Exh. GAW-1T at 51:13-19.

affordable and penalizes low-volume users within the residential rate class, since a greater portion of the bill is fixed, relative to higher use customers." Mr. Collins also testifies that increased basis charges:

> [R]educe customers' ability to control their own household utility bills. For lower usage customers, a reduction in usage has a relatively smaller impact on the bill, since a larger percentage of the bill is unaffected by their behavior. As a result, customers have a diminished price incentive to reduce their usage, and therefore their utility bill, through conservation. Increases in basic charges, therefore, tend to run counter to state policies and utility programs that promote energy efficiency and encourage customers to weatherize homes, purchase energy efficient appliances and reduce usage in other ways.

354 NWEC/RNW/NRDC argued that PSE's and Staff's proposals to increase monthly charges for residential electric customers are based on an "unprecedented treatment of line transformer costs as customer-related costs."[444] NWEC/RNW/NRDC said that if transformer costs are not treated as customer-related costs, there is no basis for increasing the monthly basic charge or imposing a new minimum bill.[445] In addition, NWEC/RNW/NRDC argues the proposals to increase monthly charges are regressive rate designs that would hurt low-income customers and impose barriers to conserving energy.

355 NWEC/RNW/NRDC echoed The Energy Project's argument that increasing basic charges disproportionately impacts low-income customers.[446] NWEC/RNW/NRDC also argued that increasing basic monthly charges sends the wrong price signal to customers.[447] NWEC/RNW/NRDC related in this connection that the Commission rejected a proposal from PacifiCorp and Staff to increase the basic charge as a disincentive for customers to conserve energy. NWEC/RNW/NRDC quotes from the Commission's order, as follows:

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[444] NWEC/RNW/NRDC Initial Brief ¶ 20.

[445] NWEC/RNW/NRDC Initial Brief ¶ 23 (citing Levin, Exh. AML-13T at 2:18 to 3:3; Ball, Exh. JLB-1T at 31:23 to 32:2).

[446] NWEC/RNW/NRDC Initial Brief ¶ 32.

[447] NWEC/RNW/NRDC Initial Brief ¶ 33 (citing *See* Levin, Exh. AML-1T at 9:18 to 10:15; Watkins, Exh. GAW-1T at 49:13 to 52:2; Collins, Exh. SMC-3T at 6:6-7).

> We reject the Company's and Staff's proposals to increase significantly the basic charge to residential customers. The Commission is not prepared to move away from the long-accepted principle that basic charges should reflect only "direct customer costs" such as meter reading and billing. Including distribution costs in the basic charge and increasing it 81 percent, as the Company proposes in this case, does not promote, and may be antithetical to, the realization of conservation goals.[448]

356 In sum, NWEC/RNW/NRDC asks the Commission to reject PSE's and Staff's proposals to increase the basic charge and imposes a new minimum bill because these proposals would hurt low-income customers and frustrate efforts to conserve energy.

Commission Determination

357 We determine that neither PSE's proposal to increase basic charges for residential customers, nor Staff's recommendations to add a minimum bill to basic charges and establishing seasonal rates, should be adopted. We are not persuaded on the basis of the current record that transformer costs should be recovered in basic charges, or through a minimum bill. We have never approved such a proposal and continue to believe these costs are not customer-related costs as that term is generally understood. Transformer costs should be recovered as distribution charges subject to PSE's electric decoupling mechanism, which adequately protects the Company's recovery of its fixed costs.

ii. Miscellaneous Electric Rate Design Issues.

(a) Addition of a Third Block Rate

358 NWEC/RNW/NRDC recommends that the Commission convene another technical conference to address three-tier rate design. NWEC/RNW/NRDC points out that the Rate Design Settlement in Docket UE-141368 required PSE to propose an inverted three-tier rate structure in this docket, but it failed to do so.[449] According to NWEC/RNW/NRDC, "there are several ways in which PSE could calculate a three-tier rate structure that would promote energy conservation by making each successive block more expensive than the preceding block."[450] Considering that Staff proposed an alternative rate structure with

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[448] NEWC, Initial Brief ¶ 33 (quoting *WUTC v. Pacific Power*, Docket UE-140762, Order 08 ¶ 216 (Mar. 25, 2015).

[449] *See supra* ¶ 283.

[450] NWEC/RNW/NRDC Initial Brief ¶ 41.

three tiers in this case,[451] and that "PSE is not opposed to a three-block rate structure,"[452] NWEC/RNW/NRDC urges us to convene a technical workshop to consider options for a three-tier rate design based on a more robust record concerning the policy and technical issues surrounding a three-tier rate design, including any data that would need to be collected and analyzed to design such a rate structure.

Commission Determination

359 We agree that just as in the case of cost of service issues, this is an issue that could benefit from additional discussion among interested stakeholders outside the context of a general rate case. Commission Staff may wish to expand the subject matter stakeholders will consider in Dockets UE-170002 and UG-170003, or initiate a separate process for this purpose.

(b) Should the Commission require PSE to propose a net metering rate schedule?

360 Staff witness Mr. Ball testified that "[n]et metering customers should be prioritized for advanced metering infrastructure (AMI) installations, if possible, before the next general rate case. He recommended that if the Company is unable to deploy AMI to these customers before the next rate case, then PSE should perform a demand study for these customers and recommend a separate tariff schedule for net-metering customers in its next general rate case.[453]

361 PSE stated it is willing to perform a demand study for net metering customers as suggested by Commission Staff and has already begun designing a program to collect the requested information for these customers. However, PSE argued, the Company cannot reprioritize the roll out of AMI. PSE says "this will occur over several years in a deliberate manner and reprioritizing the AMI roll out would significantly increase the costs and delay the roll out." Finally, PSE argued it is premature to establish a separate rate schedule for net metering customers. PSE said, however, that the Company is committed to compiling interval load data and responding to Staff's proposal in its next general rate case.[454]

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[451] Ball, Exh. JLB-1T at 44:1-2.

[452] Piliaris, Exh. JAP-1T at 60:11-15.

[453] Ball, Exh. JLB-1T at 51:6-13.

[454] *Id.* at 67:2-68:3.

Commission Determination

362 Given PSE's commitments discussed above, we find it unnecessary to address this question further in this Order.

(c) Electric Lighting Schedules

363 PSE proposed three general changes to electric lighting Schedules 50 – 59:

- Consolidate the range of wattage offerings for the Light Emitting Diode (LED) rates into contiguous groups;
- Update rates using current cost study information; and
- Remove the "Wattage Including Driver" rate component.[455]

364 Mr. Ball testified in response that PSE presented a principled cost study that fairly allocates costs across the various lighting schedules and simplifies the rates for both customers and PSE. Mr. Ball also said that the proposed revisions could reduce regulatory burden by eliminating the need for PSE to modify its tariff to offer different LED wattage levels. Mr. Ball recommended that the Commission approve the Company's proposed revisions to the existing electric lighting schedules.

Commission Determination

365 No party opposed PSE's recommended changes to these lighting schedules and they are supported by the record. We find they should be approved.

(d) Revisions to PSE's Bills

366 Public Counsel argued that the Commission should adopt Mr. Watkins' recommendations "that would make electric residential customers' bills easier to read and comprehend.[456] Doing so would allow customers to have better information about their energy usage, which could positively affect conservation efforts.[457]

367 PSE argued that the Commission should reject Public Counsel's proposal that PSE provide a summary sheet within its tariff that shows the all-in price of electricity. PSE

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[455] Piliaris, Exh. (JAP-1T) at 78:6-9.

[456] Watkins, Exh. GAW-1T at 51:20 64:2.

[457] Watkins, Exh. GAW-1T at 51:20 64:2.

argues that this is unnecessary and duplicative of information already available to customers on their bills and on the Company's website.[458]

Commission Determination

368 We agree with PSE that Public Counsel's proposal is unnecessary considering that this information already is available to customers.

2. Natural Gas Cost of Service, Rate Spread, and Rate Design

369 The parties' Settlement Stipulation does not address natural gas cost of service, rate spread, or rate design issues. We resolve these issues here considering the full record and the parties' Initial and Reply Briefs that result in some issues becoming uncontested.

a. Cost of Service Study; Rate Spread

370 PSE reviewed and updated the classification and allocation factors used in its Purchased Gas Adjustment (PGA) filings for the first time in a decade because of significant changes in its resource mix.[459] PSE classified purchased gas costs into two components: demand and variable.[460] Mr. Piliaris' testimony details the costs that are included in each component[461] and how the costs are allocated to the customer classes.[462] None of the other parties disputed PSE's proposed classification and allocation. PSE requests that we approve this methodology for use in future PGA filings.

371 Staff and NWIGU raised objections to PSE's natural gas COS study that relate to allocation of the costs of gas distribution mains. PSE used the peak and average methodology for allocating these costs. This methodology allocates gas demand costs based on a combination of peak demand and average demand (or average throughput).[463] Using this approach, PSE's demand-related gas distribution mains were allocated 33

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[458] *Id.* at 68:5-17.

[459] *See* Piliaris, Exh. JAP-1T at 49:9-50:4.

460 *See* Piliaris, Exh. JAP-1T at 50:5-7.

[461] *See* Piliaris, Exh. JAP-1T at 50:8-20; Piliaris, Exh. JAP-12.

[462] *See* Piliaris, Exh. JAP-1T at 51:1-52:9; Piliaris, Exh. JAP-14.

[463] *See* Piliaris, Exh. JAP-1T at 43:5-15.

percent on average demand and 67 percent on design day peak demand.[464] In support of this approach, Mr. Piliaris testified as follows:

> The peak and average methodology's use of system load factor provides a reasonable basis for classifying and allocating these costs. This peak and average approach reflects a balance between the way the gas system is designed (to meet peak demand) and the way it is utilized on an annual basis (throughput based on gas usage that occurs during all conditions, not only peak conditions). It also acknowledges previous Commission guidance that some portion of gas demand costs should be allocated based on energy use.[465]

372 PSE argued that its approach recognizes that all customers benefit from the gas distribution system of medium to large mains as a whole, not just from the part of its gas mains through which gas flows to reach the individual customer. PSE explained that:

> The Company's gas distribution system is a network of pipes that provides benefits to customers in addition to providing the stretch of pipe through which molecules flow to reach the individual customer. PSE's approach [to cost allocation] avoids the practice of using a customer's physical location on the system to determine the costs assigned to that customer, which has been opposed in past cases. Further, it exempts large gas customers from the cost of the smallest diameter mains (less than two inches), because the smallest main[s are] in isolated locations on the system and [are] unlikely to benefit large commercial and industrial customers.[466]

373 PSE said that the Company's approach to cost allocation addresses concerns regarding cost responsibility for two-inch mains by allocating a portion of it to all customers and excluding the largest interruptible customers from a portion of it.[467] PSE said its approach was recently validated by a third-party consultant.[468]

374 Mr. Ball testified for Staff disputing the Company's use of the design day standard to determine the peak portion of the peak and average allocation, arguing that it does not

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[464] *See* Piliaris, Exh. JAP-1T at 43:17-20, 44:12-47:15.

[465] Piliaris, Exh. JAP-1T at 44:3-9.

[466] PSE Initial Brief ¶ 125.

[467] *See* Piliaris, Exh. JAP-1T at 47:18-48:13.

[468] *See* Piliaris, Exh. JAP-46CT at 74:24-75:13, citing final report by Brown, Williams, Moorehead & Quinn in Docket UG-151663.

reflect the way that the system is used, and is therefore not sufficiently reflective of cost causation.[95] Staff allocates capacity costs in its COS study using the average class use in the highest five-day period for each of the last three years.[469] Under this proposal, Mr. Ball testified, "the average represents each class's actual use during periods of peak demand on the system."[470]

375 Mr. Ball testified, however, that PSE's "allocation methodology uses various factors, including the size of distribution mains, annual throughput, peak demand, and customer type to assign distribution plant costs to each of the customer classes."[471] Further, he said "[t]he Company presented what appears to be a fair and consistent methodology that recognizes both how a system is designed and how it is actually used."[472] Staff therefore finds PSE's main allocation methodology "acceptable" for purposes of this case.[473]

376 Public Counsel stated in its Initial Brief that, based on Mr. Watkin's review, Public Counsel finds PSE's approach to assigning the costs of distribution mains reasonable. In addition, Public Counsel said that "[t]he proposed rate spread distributes the increase across the customer classes to reflect the proper weight and consideration given to the cost of service study in light of the Commission's practices and policies."

377 NWIGU's expert witness, Mr. Brian Collins, allocated the cost of distribution mains based on class peak responsibility, which allocates capacity-related costs based on the coincident demands of the various classes expected on the design day peak.[474] NWIGU argued that this approach to allocation "more accurately reflects cost causation, and as a result, produces better price signals and encourages customers to make economic consumption decisions."[475] NWIGU explains briefly its rationale for allocating a significant portion of the total fixed cost of PSE's gas distribution system based on design day peak and describes its approach as being "defensible."[476] Having said that, NWIGU nevertheless recommends that we "not adopt any specific methodology in this case and,

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[469] Ball, Exh. JLB-1T at 12:2-3.

[470] Ball, Exh. JLB-1T at 12:3-4.

[471] Ball, Exh. JLB-1T at 12:12-14.

[472] Ball, Exh. JLB-1T at 12:20-22.

[473] Ball, Exh. JLB-1T at 12:19-20.

[474] Exhibit No. BCC 1-T at p.3, lines 12-27.)

[475] NWIGU Initial Brief ¶ 10 (citing Exh BCC 1-T at16:3-14).

[476] NWIGU Initial Brief ¶ 12.

instead, apply any rate changes in this case on an equal percent of margin basis."[477] NWIGU argued that this will maintain the status quo and allow all parties the opportunity to continue participating in the ongoing generic proceeding to help develop clear guiding principles for cost of service studies to be used in future rate cases.

Commission Determination

378 We determine that we should accept NWIGU's recommendation that we not expressly choose any one cost of service methodology over the other for purposes of allocating the costs of gas distribution mains and defer any decisions on methodology to the ongoing generic proceedings in Docket UG-170003. Further, we accept NWIGU's suggestion that we effectively ignore the COS studies presented in this case and apply a rate spread based on an equal percent of margin basis. This effectively serves to continue the status quo that is grounded in PSE's peak and average approach, but does not mean that we endorse it, or favor it over other possible approaches.

b. Special Contracts

379 In supplemental testimony, Mr. Ball provided an updated COS study, arguing that special contract customers are paying significantly below their cost of service, which is contrary to Staff's interpretation of WAC-480-80-143.[478] He recommended that the Commission impute revenues from the class to equal its cost of service per Staff's study, which would force shareholders to absorb the differential or renegotiate their special contracts.[479] Alternatively, he recommends that the Commission impose a 59 percent rate increase on the class.[480]

380 In supplemental rebuttal, Mr. Piliaris recommends that the Commission reject Staff's proposed treatment of the Special Contracts class because, PSE contends, Staff misinterprets the special contract rule, which results in Staff failing to recognize that Special Contract customers are covering their cost of service and contributing to the Company's fixed costs as required by rule. Furthermore, Mr. Piliaris argues, Staff has

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[477] NWIGU Initial Brief ¶ 12.

[478] Ball, Exh. JLB-8T at 2:25-4:5.

[479] *Id.*, 4:7-22.

[480] *Id.*, 5:19-6:6

had multiple opportunities to address this issue, and its proposal now is unfair and unprecedented.[481]

381 PSE argued in its Initial Brief that Staff's proposal is contrary to the public interest. According to the Company, "it would be an unprecedented step by the Commission to unravel a Special Contract that the Commission has approved, in the middle of the contract term."[482] With respect to Commission Staff's alternative proposal to raise the Special Contract rates in this proceeding so that the rates reflect a 2 percent rate of return, PSE argued that "there is no basis for this arbitrary increase in the Special Contract contribution to rate of return."[483] Moreover, PSE said, the Special Contract is just that, a contract, and it cannot be unilaterally revised in this proceeding. According to PSE, "the only way to increase the rate for this Special Contract, which is not suspended in this case, would be to dramatically increase rates to Schedules 87 and 87T simply to change rates for the Special Contract, which rate is based on Schedule 87 and 87T." Such an approach is, in PSE's view, "arbitrary and unreasonable."[484]

Commission Determination

382 Although Staff presented a significant volume of testimony raising and developing this issue, and devoted a significant part of its Initial Brief to arguing it, we have no need to discuss Staff's recommendations or advocacy in detail. We find PSE's testimony and arguments in rebuttal to Staff, summarized briefly above, persuasive to the point that we simply reject Staff's recommendations without further discussion.

c. Rate Design: Basic Charges and Demand Charges

383 Mr. Piliaris proposed for PSE that we order an increase to the residential monthly basic charge for natural gas customers from $10.34 to $11. PSE relies generally on the same arguments that the Company advanced in support of its requested increase for the residential electric basic charge.[485] He also proposes to increase demand charges for non-residential gas customer classes to better align them with the demand costs identified for

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[481] Piliaris, Exh. JAP-54T at 2:3-25

[482] PSE Initial Brief ¶ 133 (citing Piliaris, Exh. JAP-54T at 13:8-16).

[483] *Id.*

[484] *Id*. (citing Piliaris, Exh. JAP-54T at 15:4-21.

[485] Piliaris, Exh. JAP-1T at 92:1-93:19.

those customers in the cost of service study,[486] and re-allocate the gas procurement charge among the non-residential firm sales customers that pay it.[487]

i. Residential Basic Charge

384 PSE proposes to increase the residential basic charge to $11 per month from its current rate of $10.34 per month.[488] According to the Company's analysis, the cost of providing this service is $15.62.[489] PSE thus characterizes its proposal as a gradual move towards the cost of service. Commission Staff proposes a higher basic charge of $12.04 per month,[490] and PSE approves of the greater alignment of customer costs and customer-related revenue presented in that proposal.

385 Mr. Ball testified that his COS study supports increasing the residential basic charge from $10.34 to more than $15, but supported a smaller increase of $1.70, for a total recommended basic charge of $12.04.[491] In its Initial Brief, however, Staff recommends that we accept PSE's proposed increase to $11.00.

386 Mr. Watkins, for Public Counsel, supports the Company's request to increase the monthly basic charge for residential natural gas customers to $11.[492] Mr. Watkins performed a residential customer cost analysis to evaluate the reasonableness of PSE's proposed natural gas basic charge. Because PSE's proposal is lower than the results of Mr. Watkins's analysis, Public Counsel accepts PSE's proposed $11.00 residential basic monthly charge.[493]

387 The Energy Project acknowledged that PSE's proposed increase in the natural gas customer charge is more modest than what it proposed for residential electric customers and that Public Counsel witness Glenn Watkins' cost analysis concludes that the requested amount is reasonable in terms of cost recovery. The Energy Project argues, however, that as a policy matter it continues to have concerns about the disproportionate

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[486] Piliaris, Exh. JAP-1T at 95:1.

[487] Piliaris, Exh. JAP-1T at 96:9-97:6.

[488] *See* Piliaris, Exh. JAP-1T at 91:1-93:22.

[489] *See id.* at 91:4-5.

[490] *See* Ball, Exh. JLB-1T at 22:1-2.

[491] Ball, Exh. JLB-1T at 24:1-8.

[492] Public Counsel Initial Brief ¶ 34; *see also*Watkins, Exh. GAW-1T at 69:18-23.

[493] *Id.*

impact of a fixed cost increase on low-income natural gas customers who use limited amounts of gas, as well as the negative impact on conservation.[494] In addition, The Energy Project argued that since the parties to the Settlement Stipulation proposed a significant natural gas rate decrease, it is an inopportune time to include an increase in another part of the rate structure.[495] The Energy Project believes this is likely to be viewed by customers as contradictory and confusing. The Energy Project recommends that the natural gas customer charge remain at its current level.

Commission Determination

388 We find PSE's proposed increase to the basic charge for residential natural gas service to be reasonable, based on actual customer costs that are significantly higher than the current rate of $10.34 and that the charge would be significantly lower than what the actual costs suggest would be appropriate. PSE's attention to the principles of gradualism and rate stability is appropriate. Considering these facts and the consensus supporting PSE's proposed increase among parties who elected to address this issue, we determine the increase to $11.00 should be approved.

ii. **Demand Charges for Non-Residential Rate Schedules; Gas Procurement Charges**

389 PSE proposed to move non-residential demand charges 25 percent towards their calculated cost of service (*i.e.*, closer to parity). Commission Staff supports PSE's proposal.[496] No other party provided evidence on this issue.

390 PSE first implemented its Gas Procurement Charge in 2005 as part of the Company's 2004 general rate case. Before then, the costs now recovered by this charge were recovered from all customers through base rates. The Gas Procurement Charge recovers the costs associated with procuring and managing gas supply for sales customers. It also recovers the cost associated with PSE's storage facilities used to manage gas supply for its sales customers. This charge currently applies to non-residential gas customers served under gas Schedules 85, 86, and 87.[497]

[494] The Energy Project Initial Brief ¶ 10.

[495] *Id.*

[496] Ball, Exh. JLB-1T at 55:1-56:6.

[497] Piliaris, Exh. JAP-1T at 97:11-20.

391 PSE proposed in this case to extend the application of this charge to non-residential customers served under Schedules 31 and 41. PSE also proposes to eliminate the Gas Procurement Credit for customers served under Schedule 31T and 41T and to update the Gas Procurement Charge to reflect current costs for each schedule to which it applies.[498]

392 Mr. Piliaris testified that PSE proposed to add this charge to the bills of Schedule 31 and 41 customers to align better with the rate structure of the interruptible sales schedules that have a similar charge. He explained that, as currently applied, customers find it confusing that firm transportation customers get a credit for these procurement costs while interruptible sales customers receive a charge. When this charge was originally proposed in 2004, it was intended to recover the associated supply-related costs only from sales customers so that these costs were not borne by transportation customers who did not receive the services associated with these costs.[499]

393 Mr. Piliaris explained further that when PSE's then-current transportation Schedule 57 was reorganized in the Company's 2007 general rate case into the current set of parallel rate schedules (*i.e.,* Schedules 31T, 41T, 85T, 86T and 87T), PSE's cost of service studies retained the pairing of sales and transportation customers (*e.g.,* Schedule 85 and 85T) to maintain consistent delivery rates for each pairing of parallel schedules. To ensure that the new Schedules 85T, 86T and 87T did not bear the supply-related costs associated with the procurement charge, they were only recovered from their parallel Schedules 85, 86 and 87. However, two other transportation schedules were also created in 2007 (*i.e.,* Schedules 31T and 41T) that did not receive the same treatment. As a result, since that time, Schedules 31T and 41T have been absorbing these costs in their delivery charges. Mr. Piliaris noted that service taken under these transportation schedules has grown greatly since they were first created, which has raised the importance of addressing this issue. He noted that the current proposal simply corrects this oversight by extending the procurement charge to Schedules 31 and 41 so that the procurement-related costs that are allocated to their respective cost of service classes are not absorbed into the shared delivery charges of their paired transportation schedules.

394 Finally, Mr. Piliaris testified that PSE is extending the current methodology for calculating this charge to customers served under Schedules 31 and 41. He explained that, "in simple terms, these rates are calculated by first identifying the allocated gas

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[498] Piliaris, Exh. JAP-1T at 98:3-8.

[499] Piliaris, Exh. JAP-1T at 98:10-17.

supply and storage costs allocated to each rate group, subtracting certain cost associated with gas balancing and dividing the total by the group's pro forma sales therms."[500]

Commission Determination

395 PSE's proposed changes to procurement charges, as discussed above, are uncontested and supported by the record. We determine that they should be approved.

iii. Miscellaneous Rate Design Issues for Non-Residential Natural Gas Rate Schedules

396 PSE is proposing three additional, related changes to its base natural gas tariffs for non-residential gas customers. First, PSE proposes to implement annual maximum volume limitations on Schedules 41 and 41T, effectively requiring customers exceeding these volume limits to take service on Schedule 85 or 85T. Second, and related to the first, PSE proposes to eliminate the existing annual minimum load charge on Schedules 85 and 85T. Third, to ease the transition of customers from Schedules 41 or 41T to Schedules 85 or 85T, PSE proposes to charge fully-firm customers on Schedules 85 and 85T based on their actual demands and to relieve gas sales customers receiving fully-firm service of the obligation to sign a separate customer agreement for service under these schedules.

397 PSE proposed to limit the size of customers that can take service under Schedules 41/41T. At present, Schedules 41/41T have an eligibility threshold of 12,000 therms per year, but no maximum limit. In this case, PSE proposes to impose a load limit of 150,000 therms per year, which in effect would automatically move customers that are large enough for Schedules 85/85T to those schedules. Currently, customers are only automatically moved to another tariff if they fail to meet the minimum load requirements of their current tariff.

398 PSE argues that the change is in the interest of customers because they will pay lower rates on Schedules 85/85T than on Schedules 41/41T, but may not have the sophistication to know this is the case.[501] The Company states that 92 customers would be automatically moved if the requested change is granted.[502]

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[500] Piliaris, Exh. JAP-1T at 99:13-17. *See also* Exh. JAP-27 (summarizing calculations of these charges).

[501] Piliaris, Exh. JAP-1T at 102:1-103:1.

[502] Piliaris, Exh. JAP-1T at 101:19-20.

399 To facilitate the transition of firm customers to an interruptible schedule, PSE also proposes two administrative changes to Schedules 85/85T. First, PSE proposes to eliminate the minimum annual load charge, which requires customers on the schedule to pay for at least 180,000 therms each year.[503] Second, the Company proposes to allow customers on Schedules 85/85T to pay demand charges based on actual usage, allowing them to remain firm customers despite being on an interruptible tariff.[504] Currently, customers on Schedules 85/85T default to interruptible service, but can sign service agreements with the Company to make some or all of their usage firm. PSE proposes to flip that, allowing customers to default to firm service, but sign agreements with the Company to move some portion of their load to interruptible service.

400 Other than Mr. Piliaris' testimony for PSE, the record is not well developed on this issue. No party explicitly responded to PSE's proposal to cap usage on Schedules 41/41T or the related changes to Schedules 85/85T.

Commission Determination

401 Based on our detailed review of PSE's proposals we have several concerns. First, PSE's representation that customers moving from Schedules 41/41T to 85/85T would be paying lower rates appears to be misleading. Our analysis shows that a customer with annual demand of 150,000 therms – the cutoff between the two schedule groups – would face a monthly rate increase of $261.60 (11.63 percent) under the proposal. Table 5 summarizes the increase:

Table 5. Monthly bill impact of moving a customer from schedules 41/41T to 85/85T[505]

		Basic Charge	1st Block[506]	2nd Block	3rd Block	Gas procurement	Demand Charge	Total Bill
41/ 41T	Rate	$116.92	$0.14145	$0.11386	N/A	$0.00671	$1.17	
	Subtotal	$116.92	$707.25	$853.95	--	$83.88	$487.89	$2249.89
85/	Rate	$593.83	$0.10756	$0.05322	$0.05092	$0.00582	$1.20	

503 Piliaris, Exh. JAP-1T at 104:3-105:11.

504 Piliaris, Exh. JAP-1T at 105:12-106:11.

505 This analysis makes the following simplifying assumptions: A customer with annual usage of 150,000 therms and a load factor of 1 (*i.e.*, constant load across all hours of the year), resulting in monthly usage of 12,500 therms and demand of 417 therms.

506 The first block of Schedules 41/41T applies to the first 5,000 therms per month. The first block of Schedules 85/85T applies to the first 25,000 therms per month.

85T	Subtotal	$593.83	$1344.50	--	--	$72.75	$500.40	$2511.48

402 As the table shows, Schedule 41/41T customers would face significantly higher basic charges on Schedules 85/85T and incrementally higher demand charges. With a second block rate in Schedule 41/41T that is only 0.63 cents higher than the first block in Schedules 85/85T, customers would not be able to make up the difference in those increased fixed costs through lower volumetric rates. Since the lower block rates of Schedules 85/85T do not apply until 25,000 and 50,000 therms per month, respectively, customers would have to have very high usage before they would be better off on Schedules 85/85T. In fact, our analysis shows that a current Schedule 41/41T customer would have to use 27,800 therms per month – about 334,000 therms per year – before they would break even on Schedules 85/85T. Of course, this analysis is predicated on a customer maintaining the same level of service (fully firm) after moving to Schedules 85/85T, and does not consider the potential for customers to respond to enhanced price signals on Schedules 85/85T and transfer some of their load to interruptible service.

403 While we do not foreclose the possibility that the changes PSE proposed in this case, or similar changes that take impacts more fully into account than is evident on the record here, might be implemented in a future case, we will not approve them at this time. We are not aware whether any Schedule 41 customers were represented in this case, but it does not appear so. Nor does it appear that any party focused attention on these issues in such a way as to afford these customers some degree of protection from changes in PSE's tariffs that could have significant rate impacts. If PSE brings these proposals forward in a future case, we will expect the Company to demonstrate that it has reached out to and fully informed potentially affected customers so they can make informed decisions concerning participation in the proceeding.

FINDINGS OF FACT

404 Having discussed above in detail the evidence received in this proceeding concerning all material matters, and having stated findings and conclusions upon issues in dispute among the parties and the reasons therefore, the Commission now makes and enters the following summary of those facts, incorporating by reference pertinent portions of the preceding detailed findings:

405 (1) The Washington Utilities and Transportation Commission (Commission) is an agency of the State of Washington vested by statute with the authority to regulate rates, regulations, practices, accounts, securities, transfers of property and affiliated interests of public service companies, including electric and natural gas companies.

406 (2) Puget Sound Energy (PSE) is a "public service company," an "electrical company," and "gas company" as those terms are defined in RCW 80.04.010 and used in Title 80 RCW. PSE provides electric and natural gas utility service to customers in Washington.

407 (3) PSE's currently effective rates were determined on the basis of the Commission's Final Order *In the Matter of the Petition of Puget Sound Energy and NW Energy Coalition For an Order Authorizing PSE to Implement Electric and Natural Gas Decoupling Mechanisms and to Record Accounting Entries Associated with the Mechanisms*, Dockets UE-121697 and UG-121705 (consolidated) (Decoupling) and *Washington Utilities and Transportation Commission v. Puget Sound Energy*, Dockets UE-130137 and UG-130138 (consolidated) (ERF), Order 07 - Final Order Granting Decoupling Petition and Final Order Authorizing ERF Rates (June 25, 2013) (Order 07-2013 Rate Plan).

408 (5) The rates established by Order 07-2013 Rate Plan, updated PSE's rates previously established in 2012 consistent with *WUTC v. Puget Sound Energy, Inc.,* Dockets UE-111048 and UG-111049 (*consolidated*), Order 08 (May 7, 2012). Under the Rate Plan, PSE's rates were adjusted annually reflecting implementation of full decoupling of the Company's electric and natural gas rates and allowed percentage increases designed to encourage careful cost management practices and efficiency efforts.

409 (6) The Rate Plan resulted in the following financial results:

- An approximate $30 million net electric and gas rate increase from the expedited rate filing in July 2013.
- Annual K-factor increases to delivery revenues of 3.0 percent for electric and 2.2 percent for gas in July 2013, January 2014, January 2015, January 2016, and January 2017.
- Recognition of net electric decoupling revenue of approximately $59 million and net gas decoupling revenue of approximately $116 million from July 1, 2013, through September 30, 2016.

These financial results, coupled with cost savings and efficiencies realized during the Rate Plan effective period, allowed PSE to consistently earn rates of return and returns on equity slightly below its authorized rate of return and return on equity on an adjusted actual basis across all time periods demonstrating that the Rate Plan mitigated the effects of regulatory lag and attrition during the Rate Plan effective period.

410 (7) On January 13, 2017, PSE filed this general rate case with the Commission proposing revisions to its currently effective Tariffs WN U-20, Electric Service, and Tariff WN U-2, Natural Gas Service, as required under the terms of the Rate Plan and a subsequent order that postponed the original required filing date by approximately 10 months.

411 (8) On September 15, 2017, PSE, Staff, ICNU, FEA, Kroger, Energy Project, Sierra Club, State of Montana, NWEC/RNW/NRDC, and NWIGU filed a Settlement Stipulation and a joint narrative statement in support. The State of Montana filed a letter supporting the settlement. Settling Parties filed individual party testimonies on September 15 and 18, 2017. Public Counsel filed testimony opposing the settlement, in part, on September 22, 2017. The Settlement Stipulation is attached to this Order as Appendix B.

412 (9) The Settlement Stipulation addressed all issues relevant to PSE’s revenue requirements for electric operations and natural gas operations, and a number of non-revenue issues. Some non-revenue issues were not addressed by the Settlement Stipulation and remained fully contested, including most decoupling proposals, PSE’s proposed Electric Cost Recovery Mechanism, and some electric and all natural gas cost of service, rate spread, and rate design issues identified by the parties.

413 (10) Thirty-three adjustments to electric revenue requirements and twenty-one adjustments to natural gas revenue requirements reflected in the parties’ Settlement Stipulation are uncontested. One additional adjustment to both electric and natural gas revenue requirements is a “pass-through” adjustment based on an uncontested methodology. These 56 adjustments are depicted in Appendix A to this Order, including revenue requirements metrics. These uncontested adjustments are supported by substantial competent evidence in the record of this proceeding. We find they should be approved without exception or condition.

414 (11) Two issues addressed by the Settlement Stipulation, but contested by Public Counsel, are the principle drivers of overall revenue requirements in this proceeding. The first is the cost of capital; specifically, the rate of return on equity. The second is the depreciation expense attributable to certain coal-fired power plants known as Colstrip Units 1 through 4, in which PSE has ownership interests. Colstrip raises non-revenue issues as well, including the proposed use of Treasury Grants and not yet monetized Production Tax Credits to pay for increased depreciation expenses that arise under the terms of the Settlement Stipulation and, later, decommissioning and remediation costs. The Settling Parties propose reasonable resolutions of these issues in their Settlement Stipulation, as discussed in detail in the body of this Order.

415 (12) The Settlement Stipulation proposes reasonable resolutions to the following revenue requirements issues: Electric Adjustment 13.06 and Natural Gas Adjustment 11.06 (Depreciation Study); Electric Adjustment 13.15 and Natural Gas Adjustment 11.15 (Pension Plan); Electric Adjustment 13.19 and Natural Gas Adjustment 11.19 (Environmental Remediation); Electric Adjustment 14.05 (Storm Damage); and Public Counsel Adjustment B-5 (Plant Held for Future Use), as discussed in the body of this Order.

416 (13) The Settlement Stipulation's proposed resolution of the issues identified above in Findings of Fact (11) and (12) are well-supported by substantial competent evidence and provide reasonable resolutions of the issues considering the facts. Public Counsel's "alternative viewpoints" or arguments opposing the Settlement Stipulation's proposed resolution of these issues are not well-supported by the record and are not persuasive.

417 (14) The Settlement Stipulation is neither ambiguous nor unclear with respect to the guidance it provides PSE and the parties should PSE elect to seek approval of an Expedited Rate Filing (ERF) during the 12 months following the date of this Order.

418 (15) A collaborative process to give considered attention to the question whether to continue PSE's water heater program, as provided by the Settlement Stipulation, is a superior alternative to Public Counsel's proposal to simply discontinue the program on the basis of the current record, which is spare, at best.

419 (16) The Settlement Stipulation's proposal to update the Service Quality Index No. 5 metric is reasonable considering advances in communications technology and practice since the current metric was established 20 years ago and is unlikely to result in any deterioration in service quality. The revised standard proposed by the Settling Parties is supported by substantial competent evidence as discussed in the body of this Order.

420 (17) No party challenges, and there is substantial competent evidence supporting, a determination of prudence with respect to each of the following eight projects, as discussed in the body of this Order:

- Snoqualmie Falls hydroelectric redevelopment project.
- Acquisition of the Buckley Natural Gas Distribution System.
- Acquisition and development of the Glacier Battery Storage System.
- Development and construction of the Ardmore Substation.
- Power purchase agreement with Public Utility District No. 1 Public Utility District No. 1 of Douglas County, Washington to purchase power from the Wells Hydroelectric Project.
- Acquisition of transmission capacity from Bonneville Power Administration (BPA) for the Goldendale Generation Facility (38 MW) and the Mint Farm Generation Facility (15 MW).
- Renewal of agreements for transmission capacity from BPA associated with the Coal Transition Power Purchase Agreement (100 MW), the Mint Farm Generation Facility (20 MW), and purchases from Garrison, Montana (94 MW).
- Total amount of actual costs accumulated and deferred until September 30, 2016, associated with PSE's electric and natural gas Environmental Remediation program.

421 (18) The record establishes that PSE's decoupling mechanisms are working as intended. We find these mechanisms should be continued at this time but also find it prudent for the Commission to review the operation of the mechanisms again after four years from the date of this Order.

422 (19) Greater homogeneity among customers within individual groups will reduce rate volatility and cross-subsidization by better aligning customers with similar load profiles following PSE's proposal for five electric groups and two natural gas groups.

423 (20) We find that the Commission's approach to decoupling, going forward, should continue to use a revenue-per-customer approach for most costs and a revenue-per-class approach for fixed production costs. We reject the "complete decoupling" approach advocated by Public Counsel and The Energy Project because it fails to take into account all relevant factors and ignores salient facts, as discussed in the body of this Order.

424 (21) PSE's proposal to increase the soft cap for the electric decoupling mechanism from 3 percent to 5 percent is unsupported by any evidence of financial harm to PSE or customers from the current 3 percent cap.

425 (22) We find it appropriate to increase the soft cap for natural gas decoupling to 5 percent because large deferrals have developed under the natural gas decoupling mechanism with unrecovered balances remaining on PSE's books for more than one year creating an earnings challenge for PSE considering GAAP requirements.

426 (23) PSE's earnings sharing mechanism should be based on actual, not theoretical earnings, thus requiring that normalizing adjustments be removed from the earnings test.

427 (24) PSE's proposed 25 basis point dead band for its earnings test could result in a higher rate of return than shown to be appropriate by the cost of capital evidence in the record and is, therefore, unacceptable.

428 (25) PSE failed to carry its burden to show the need for the Company's proposed Electric Cost Recovery Mechanism.

429 (26) It is necessary to limit the application of the Commission's decisions on the contested cost of service study and rate spread issues by giving them effect only with respect to this case while allowing ongoing generic proceedings concerning these issues to continue.

430 (27) The record does not support the recovery of transformer costs in residential electric basic charges and PSE otherwise failed to carry its burden to justify a proposed increase in the basic charge for residential electric service.

431 (28) PSE's proposed increase to the basic charge for residential natural gas service was shown to be reasonable based on actual customer costs that are significantly higher than the current rate of $10.34 and that the charge would be significantly lower than what the actual costs suggest would be appropriate thereby reflecting appropriately the principle of gradualism.

432 (29) The record does not support PSE's proposed changes with respect to non-residential natural gas schedules 41, 41T, 85, and 85T.

433 (30) PSE's currently effective electric rates do not provide sufficient revenue to recover the costs of its operations and provide a rate of return adequate to compensate investors at a level commensurate to what they might expect to earn on other investments bearing similar risks. In contrast, PSE's currently effective natural gas rates over recover the Company's costs of operations and provide returns greater than what is required to continue attracting investors.

CONCLUSIONS OF LAW

434 Having discussed above all matters material to this decision, and having stated the following summary conclusions of law, incorporating by reference pertinent portions of the preceding detailed conclusions:

435 (1) The Washington Utilities and Transportation Commission has jurisdiction over the subject matter of, and parties to, these proceedings.

436 (2) PSE is an electric company, a natural gas company, and a public service company subject to Commission jurisdiction.

437 (3) At any hearing involving a proposed change in a tariff schedule the effect of which would be to increase any rate, charge, rental, or toll theretofore charged, the burden of proof to show that such increase is just and reasonable will be upon the public service company. RCW 80.04.130 (4). The Commission's determination of whether the Company has carried its burden is adjudged on the basis of the full evidentiary record.

438 (4) PSE's existing rates for electric service are neither fair, just, and reasonable, nor sufficient, and should be adjusted prospectively after the date of this Order.

439 (5) PSE's existing rates for natural gas service are not fair, just, and reasonable, and should be adjusted prospectively after the date of this Order.

440 (6) The Settlement Stipulation's proposed resolution of the issues identified above in Findings of Fact (11) and (12) are lawful and in the public interest reaching, as they do, end results in terms of overall rates that are fair, just, reasonable, and sufficient.

441 (7) There is no legal impediment to PSE seeking approval of an ERF filed within 12 months following the date of this Order following the guidance offered by the terms of the Settlement Stipulation.

442 (8) The Commission should approve and adopt the Settling Parties' Settlement Stipulation as its resolution of the issues addressed by its terms. The Settlement Stipulation should be incorporated by reference into the body of this Order, as if set forth in full.

443 (9) The legal and policy bases supporting the continued operation of PSE's decoupling mechanisms are firmly established by the Commission's prior orders and policy statements and as discussed in the body of this Order.

444 (10) The Commission should enforce the terms of the Rate Design Settlement in Docket UE-141368 based on its plain terms and meaning, including the explicit requirement that the demand and energy classification percentages will be set in this proceeding at 25 percent demand and 75 percent energy.

445 (11) The Commission's resolution of contested issues concerning cost of service studies, rate spread, and rate design should be limited to the resolution of these issues in this proceeding in deference to ongoing collaboratives in Dockets UE-170002 and UG-170003.

446 (12) PSE should be authorized and required to make a compliance filing in these consolidated dockets to recover in prospective rates its revenue deficiency of $20,160,334 for electric operations and to remove from prospective rates its revenue sufficiency of $35,465,639 for natural gas operations.

447 (13) The Commission Secretary should be authorized to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Order.

448 (14) The Commission should retain jurisdiction over the subject matters and the parties to this proceeding to effectuate the terms of this Order.

ORDER

THE COMMISSION ORDERS THAT:

449 (1) The proposed tariff revisions Puget Sound Energy (PSE) filed in these dockets on January 13, 2017, and suspended by prior Commission order, are rejected.

450 (2) PSE is authorized and required to make a compliance filing in this docket including all tariff sheets that are necessary and sufficient to effectuate the terms of this Final Order. The stated effective date included in the compliance filing tariff sheets must allow five business days after the date of filing for Commission review.

451 (3) The Commission Secretary is authorized to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Final Order.

452 (4) The Commission retains jurisdiction over the subject matters and parties to this proceeding to effectuate the terms of this Order.

DATED at Olympia, Washington, and effective December 5, 2017.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DAVID W. DANNER, Chairman

ANN E. RENDAHL, Commissioner

JAY M. BALASBAS, Commissioner

NOTICE TO PARTIES: This is a Commission Final Order. In addition to judicial review, administrative relief may be available through a petition for reconsideration, filed within 10 days of the service of this order pursuant to RCW 34.05.470 and WAC 480-07-850, or a petition for rehearing pursuant to RCW 80.04.200 and WAC 480-07-870.

APPENDIX A

ADJUSTMENTS TO REVENUE REQUIREMENTS

Electric Settlement Adjustments and Revenue Requirement

Adjustment (a)	Description (b)	NOI (c)	Rate Base (d)	Revenue Requirement (e)
	Results of Operations	**401,002,972**	**5,153,204,462**	**(15,119,001)**
	Uncontested Settlement Adjustments			
13.01	Revenues & Expenses	(29,139,114)	-	47,070,619
13.02	Temperature Normalization	17,527,344	-	(28,313,247)
13.03	Pass-Through Revs. & Exps.	(1,000,540)	-	1,616,249
13.04	Federal Income Tax	(27,023,239)	-	43,652,686
13.05	Tax Benefit of Proforma Interest	54,067,781	-	(87,339,785)
13.06A	Reg. Asset Colstrip	-	-	-
13.07	Normalize Injuries & Damages	69,387	-	(112,087)
13.08	Bad Debts	681,065	-	(1,100,176)
13.09	Incentive Pay	(109,903)	-	177,535
13.10	D&O Insurance	16,141	-	(26,074)
13.11	Interest on Customer Deposits	(176,606)	-	285,284
13.12	Rate Case Expenses	(264,905)	-	427,920
13.13	Deferred G/L on Property Sales	171,200	-	(276,552)
13.14	Property & Liability Ins	66,147	-	(106,852)
13.16	Wage Increase	(1,357,716)	-	2,193,221
13.17	Investment Plan	(96,705)	-	156,214
13.18	Employee Insurance	(121,751)	-	196,674
13.20	Payment Processing Costs	(2,010,221)	-	3,247,263
13.21	South King Service Center	434,046	15,915,060	1,252,721
13.22	Excise Tax and WUTC Filing Fee	10,262	-	(16,577)
13.23	ISWC and RB Adjustment	-	19,006,090	2,333,350
13.24	Legal Cost Adjustment	-	-	-
14.01	Power Costs	1,185,175	-	(1,914,503)
14.02	Montana Electric Energy Tax	148,016	-	(239,101)
14.03	Wild Horse Solar	137,890	(1,969,341)	(464,518)
14.04	ASC 815 (Prev. SFAS 133)	(41,672,584)	-	67,316,883
14.06	Reg Assets & Liabilities	1,736,212	(44,085,326)	(8,216,927)
14.07	Glacier Battery Storage	(145,490)	2,842,787	584,026
14.08	Energy Imbalance Market	-	-	-
14.09	Goldendale Capacity Upgrade	2,156	18,140,954	2,223,656
14.10	Mint Farm Capacity Upgrade	-	19,004,590	2,333,166
14.11	White River	(3,288,310)	(4,108,724)	4,807,435
14.12	Reclass of Hydro Treasury Grants	(2,131,857)	5,739,615	4,148,394
14.13	Production Adjustment	32,769	-	(52,934)
	Contested Settlement Adjustments			
13.06	Depreciation Study	(34,311,788)	(17,155,894)	53,320,227
13.15	Pension Plan	(1,184,945)	-	1,914,132
13.19	Environmental Remediation	(925,460)	-	1,494,966
14.05	Storm Damage	(6,137,438)	-	9,914,269
	Black Box Settlement Adjustment			
13.25	Black Box Adjustment	619,051	-	(1,000,000)
	Other Adjustment			
	Revenue Effects of 4-Yr Rate Plan & Other Mechanisms[1]			(86,208,222)
	Overall Electric Revenue Requirement			***20,160,334***

[1] This adjustment reflects the offsetting rate impacts of the 2013 ERF Filing (Schedule 141), Decoupling, K-Factor and Earnings Sharing (Schedule 142), and Power Cost Adjustments (Schedule 95) which occurred during the four-year rate plan in effect since the last GRC in 2011 in Dockets UE-111048 and UG-111049.

Gas Settlement Adjustments and Revenue Requirement

Adjustment (a)	Adjustment (b)	NOI (c)	Rate Base (d)	Revenue Requirement (e)
	Results of Operations	**119,145,769**	**1,727,319,760**	**19,551,185**
	Uncontested Settlement Adjustments			
11.01	Revenues & Expenses	(32,674,131)	-	52,661,989
11.02	Temperature Normalization	16,046,445	-	(25,862,592)
11.03	Pass-Through Revs. & Exps.	736,148	-	(1,186,474)
11.04	Federal Income Tax	700,822	-	(1,129,538)
11.05	Tax Benefit of Proforma Interest	18,475,298	-	(29,777,255)
11.07	Normalize Injuries & Damages	(57,738)	-	93,058
11.08	Bad Debts	35,240	-	(56,797)
11.09	Incentive Pay	104,023	-	(167,657)
11.10	D&O Insurance	11,636	-	(18,754)
11.11	Interest on Customer Deposits	(50,137)	-	80,807
11.12	Rate Case Expenses	(280,617)	-	452,280
11.13	Deferred G/L on Property Sales	(105,090)	-	169,377
11.14	Property & Liability Ins	45,174	-	(72,809)
11.16	Wage Increase	(907,409)	-	1,462,502
11.17	Investment Plan	(46,689)	-	75,250
11.18	Employee Insurance	(58,781)	-	94,740
11.20	Payment Processing Costs	(1,449,117)	-	2,335,590
11.21	South King Service Center	212,048	7,775,116	610,622
11.22	Excise Tax and WUTC Filing Fee	33,509	-	(54,008)
11.23	ISWC and RB Adjustment		4,743,346	581,021
11.24	Legal Cost Adjustment	-	-	-
7.01	Gas Cost Recovery Mechanism	(4,003,724)	19,011,708	8,781,713
	Contested Settlement Adjustments			
11.06	Depreciation Study	13,174,098	6,587,049	(20,426,274)
11.15	Pension Plan	(572,091)	-	922,058
11.19	Environmental Remediation	(5,592,128)	-	9,013,019
	Black Box Settlement Adjustment			
11.25	Black Box Adjustment	930,675	-	(1,500,000)
	Other Adjustment			
	Revenue Effects of 4-Yr Rate Plan & Other Mechanisms[2]			(52,098,690)
	Overall Gas Revenue Requirement			***(35,465,639)***

[2] This adjustment reflects the offsetting rate impacts of the 2013 ERF Filing (Schedule 141), Decoupling, K-Factor and Earnings Sharing (Schedule 142), and Cost Recovery Mechanism (Schedule 149) which occurred during the four-year rate plan in effect since the last GRC in 2011 in Dockets UE-111048 and UG-111049.

APPENDIX B

SETTLEMENT STIPULATION AND EXHIBITS

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IDAHO PUBLIC
UTILITIES COMMISSION

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-19-04
OF AVISTA CORPORATION FOR THE	)	
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC	)	DIRECT TESTIMONY
CUSTOMERS IN THE	)	OF JOSEPH D. MILLER
STATE OF IDAHO	)	IN SUPPORT OF
	)	STIPULATION

FOR AVISTA CORPORATION

(ELECTRIC)

I.INTRODUCTION

Q. Please state your name, employer and business address.

A. My name is Joseph D. Miller and I am employed as the Manager of Pricing and Tariffs for Avista Utilities ("Company" or "Avista"), at 1411 East Mission Avenue, Spokane, Washington.

Q. Have you previously filed direct testimony in this proceeding?

A. Yes. My testimony in this proceeding covered the spread of the proposed 2020 electric revenue increase among the Company's electric general service schedules. My testimony also described the changes to the rates within the Company's electric service schedules.

Q. What is the scope of this testimony?

A. The purpose of my testimony is to describe and support the non-revenue requirement portions of the Stipulation and Settlement ("Stipulation"), filed on October 11, 2019 between the Staff of the Idaho Public Utilities Commission ("Staff'), Clearwater Paper Corporation ("Clearwater"), Idaho Forest Group, LLC ("Idaho Forest"), the Community Action Partnership Association of Idaho ("CAPAI"),the Idaho Conservation League (ICL), Walmart, Inc. (Walmart), and the Company. These entities are collectively referred to as the "Parties."

In my testimony I will explain the following Settlement components:

1. Rate Spread and Rate Design
2. Other Settlement Items

Q. Are you sponsoring any exhibits?

A. No, I am not. Company witness Ms. Andrews is sponsoring Exhibit No. 13, which is a copy of the Stipulation and Settlement filed on October 11, 2019, with the Commission.

II. RATE SPREAD & RATE DESIGN

Q. Please explain the settlement terms relating to electric cost of service.

A. In this case, the Company prepared an electric cost of service analysis that incorporated, among other things, a system load factor peak credit method of classifying production costs, allocating 100% of transmission costs to demand, and allocating transmission costs on a twelve-month coincident peak allocation factor. The Parties, however, do not agree on any particular cost of service methodology. Nevertheless, in recognition that certain rate schedules are well above their relative cost of service the Parties agree that General Service Schedules 11/12 and Large General Service Schedules 21/22 will receive a revenue decrease above the overall percentage base rate change, in order to move these schedules closer to cost-of-service parity. The majority of remaining schedules will receive revenue decreases below the overall percentage base rate change, at varying levels, that will move the majority of these schedules closer to their relative cost-of-service.

Q. How did the Stipulation address rate design?

A. For settlement purposes, the Parties agreed to the rate design changes proposed by the Company in my direct testimony. The agreed-upon rate design resulted in no changes to the basic charges, with the revenue changes collected through the volumetric energy rates. Appendix C of the Stipulation (Exhibit No. 13) provides a summary of the current and proposed rates and charges.

Q. What is the effect on retail rates, by rate schedule, of the proposed settlement?

A. The following tables reflect the agreed-upon percentage decreases by schedule for electric service:[1]

Effective December 1, 2019

Rate Schedule	**Decrease in Base Rates**	**Decrease in Billing Rates**
Residential Schedule 1	-1.0%	-1.0%
General Service Schedules 11/12	-8.4%	-8.2%
Large General Service Schedules 21/22	-4.5%	-4.4%
Extra Large General Service Schedule 25	-1.0%	-1.0%
Clearwater Paper Schedule 25P	-1.0%	-1.0%
Pumping Service Schedules 31/32	-1.6%	-1.5%
Street & Area Lights Schedules 41-48	0.0%	0.0%
Overall	**-2.8%**	**-2.8%**

Q. What are the residential bill impacts if the Commission approves the Settlement Stipulation?

A. Effective December 1, 2019, an electric residential customer using an average of 900 kilowatt hours per month would see a $0.86, or 1.0%, decrease per month for a revised monthly bill of $84.45.

III. OTHER ELEMENTS OF THE STIPULATION

Q. Please explain the settlement terms relating to the Power Cost Adjustment (PCA) authorized level of expenses.

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[1] The Parties agreed to incorporate the current Schedule 72 (Permanent Federal Tax Rate Credit) as part of base rates and to cancel Schedule 72 altogether.

A. The new level of power supply revenues, expenses, retail load and Load Change Adjustment Rate resulting from the December 1, 2019, settlement revenue requirement, for purposes of monthly PCA mechanism calculations, are detailed in Appendix A of the Stipulation (Exhibit No. 13).

Q. Please explain the settlement terms relating to the authorized base for the Electric Fixed Cost Adjustment Mechanism.

A. The new level of baseline values for the electric fixed cost adjustment mechanism resulting from the December 1, 2019, settlement revenue requirement are detailed in Appendix B of the Stipulation (Exhibit No. 13).

Q. Please explain the other issues agreed upon in the Settlement Stipulation.

A. The Parties agreed to increase funding for the Low Income Weatherization Program from the current Commission-approved levels of $800,000 to $850,000.

Second, the Parties agreed that Avista will establish an Energy Efficiency Assistance Fund ("EEAF"). The purpose of the EEAF is to provide additional funding for projects that are not otherwise fully funded through existing energy efficiency incentives, or do not otherwise qualify for traditional energy efficiency funding.

Q. Did the Parties agree as to how to fund the EEAF?

A. Yes. As part of the give and take of settlement negotiations the Parties agreed the EEAP will be funded and disbursed as follows:

i. The final deferral balance related to the "AFUDC Equity Tax Deferral", addressed in Case Nos. AVU-E-19-02 and AVU-G-19-

01, as ordered in Commission Order No. 34326 will be a source of funding. The estimated deferral balance is approximately $800,000.

ii. Avista will contribute below-the-line dollars of $800,000 in 2019 as a match to the estimated AFUDC Equity Tax Deferral (in subsection i.).

iii. The funding will be disbursed as directed by the Energy Efficiency Assistance Fund Advisory Group, a new committee of stakeholders tasked with determining which existing or new programs should receive this funding to address energy efficiency, weatherization, conservation, and low-income needs in Avista's Idaho service territory.

iv. The EEAF Advisory Group will consider the needs of all parties and remain flexible on the timing of any disbursements. Any entity seeking funding must first attempt to qualify their applicable project under Avista's existing energy efficiency programs.

v. The committee will initially consist of representatives from the following stakeholders: Avista, Staff, the Lewiston Community Action Partnership, ICL, Idaho Forest, and Clearwater. The Committee may add representatives at its discretion.

Q. Did the Stipulation address certain DSM projects specifically related to Clearwater?

A. Yes. Avista agrees to work with Clearwater to attempt to qualify the following projects for DSM funding under Tariff Schedule 90:

- Variable speed drives on the No. 1 paper machine hydropulper.
- Variable speed drives on the No. 4 power boiler demineralized water pumps.
- Energy efficient chillers and compressors for the Lurgi system.
- A variable speed drive on the No.1 paper machine white water system.
- Variable speed drives on the two waste water outfall pumps.

Q. Did the Stipulation address certain DSM projects specifically related to the Idaho Forest Group?

A. Yes. Avista agrees to work with the Idaho Forest Group to attempt to qualify the following projects for DSM funding under Tariff Schedule 90:

- Installation of information technology to gather plant information data (PI Data) on energy usage at Idaho Forest's Lewiston plant, and through an installed interface, transmit real time energy load information data for each operating station to the Idaho Forest Group and Avista. This may serve as a useful demonstration project for data interfaces with other customers on Avista's system. The total estimated cost is $300,000.

- Replacement of aging compressors, saws and other equipment with state of the art machinery at Idaho Forest's Lewiston and Grangeville plants, in order to increase productivity and energy efficiency.

Q. Is DSM funding addressed in Tariff Schedule 90?

A. Yes. Tariff Schedule 90 allows for possible DSM funding of up to 70% of the cost of the project, subject to meeting certain specified cost-effectiveness criteria. The portion of the estimated cost of these identified projects for both Clearwater and the Idaho Forest Group that is not reimbursed under Schedule 90 will be considered for funding through the EEAF, who will consider the needs of all parties and remain flexible on the timing of any disbursements.

Q. Does this conclude your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority	U-20561 ALJ Sharon Feldman

PROOF OF SERVICE

On the date below, an electronic copy of the **Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club's Response to DTE Electric Company's Second Discovery Request** was served on the following:

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The statements above are true to the best of my knowledge, information and belief.

OLSON, BZDOK & HOWARD, P.C.
Counsel for MEC-NRDC-SC

Date: November 22, 2019

By: ______________________________

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DTE Electric Company

Observed Compound Annual Total Returns on the Market

Year	Total Return	4-Year	5-Year	10-Year	20-Year	50-Year	93-Year
1926	11.6%						
1927	37.5%						
1928	43.6%						
1929	-8.4%	19.2%					
1930	-24.9%	8.0%	8.7%				
1931	-43.3%	-13.5%	-5.1%				
1932	-8.2%	-22.7%	-12.5%				
1933	54.0%	-11.9%	-11.2%				
1934	-1.4%	-5.7%	-9.9%				
1935	47.7%	19.8%	3.1%	5.9%			
1936	33.9%	31.6%	22.5%	7.8%			
1937	-35.0%	6.1%	14.3%	0.0%			
1938	31.1%	13.9%	10.7%	-0.9%			
1939	-0.4%	3.2%	10.9%	-0.1%			
1940	-9.8%	-6.5%	0.5%	1.8%			
1941	-11.6%	1.0%	-7.5%	6.4%			
1942	20.3%	-1.1%	4.6%	9.3%			
1943	25.9%	4.8%	3.8%	7.2%			
1944	19.8%	12.5%	7.7%	9.3%			
1945	36.4%	25.4%	17.0%	8.4%	7.1%		
1946	-8.1%	17.3%	17.9%	4.4%	6.1%		
1947	5.7%	12.3%	14.9%	9.6%	4.7%		
1948	5.5%	8.8%	10.9%	7.3%	3.1%		
1949	18.8%	5.1%	10.7%	9.2%	4.5%		
1950	31.7%	14.9%	9.9%	13.4%	7.4%		
1951	24.0%	19.6%	16.7%	17.3%	11.7%		
1952	18.4%	23.1%	19.4%	17.1%	13.2%		
1953	-1.0%	17.6%	17.9%	14.3%	10.7%		
1954	52.6%	22.0%	23.9%	17.1%	13.1%		
1955	31.6%	23.9%	23.9%	16.7%	12.5%		
1956	6.6%	20.6%	20.2%	18.4%	11.2%		
1957	-10.8%	17.5%	13.6%	16.4%	13.0%		
1958	43.4%	15.7%	22.3%	20.1%	13.5%		
1959	12.0%	11.1%	15.0%	19.4%	14.1%		
1960	0.5%	9.5%	8.9%	16.2%	14.8%		
1961	26.9%	19.6%	12.8%	16.4%	16.9%		
1962	-8.7%	6.8%	13.3%	13.4%	15.3%		
1963	22.8%	9.3%	9.9%	15.9%	15.1%		
1964	16.5%	13.4%	10.7%	12.8%	14.9%		
1965	12.5%	10.1%	13.2%	11.1%	13.8%		
1966	-10.1%	9.7%	5.7%	9.2%	13.7%		
1967	24.0%	9.9%	12.4%	12.8%	14.6%		
1968	11.1%	8.6%	10.2%	10.0%	14.9%		
1969	-8.5%	3.2%	5.0%	7.8%	13.4%		
1970	4.0%	7.0%	3.3%	8.2%	12.1%		
1971	14.3%	4.8%	8.4%	7.1%	11.6%		
1972	19.0%	6.7%	7.5%	9.9%	11.7%		
1973	-14.7%	4.8%	2.0%	6.0%	10.8%		
1974	-26.5%	-3.9%	-2.4%	1.2%	6.9%		
1975	37.2%	0.6%	3.2%	3.3%	7.1%	9.0%	
1976	23.8%	1.6%	4.9%	6.6%	7.9%	9.2%	
1977	-7.2%	3.8%	-0.2%	3.6%	8.1%	8.3%	
1978	6.6%	13.9%	4.3%	3.2%	6.5%	7.7%	
1979	18.4%	9.7%	14.8%	5.9%	6.8%	8.2%	
1980	32.4%	11.6%	13.9%	8.4%	8.3%	9.5%	
1981	-4.9%	12.3%	8.1%	6.5%	6.8%	10.6%	
1982	21.4%	16.0%	14.0%	6.7%	8.3%	11.2%	
1983	22.5%	17.0%	17.3%	10.6%	8.3%	10.7%	
1984	6.3%	10.7%	14.8%	14.8%	7.8%	10.9%	
1985	32.2%	20.2%	14.7%	14.3%	8.7%	10.7%	
1986	18.5%	19.5%	19.9%	13.8%	10.2%	10.4%	
1987	5.2%	15.0%	16.5%	15.3%	9.3%	11.5%	
1988	16.8%	17.8%	15.4%	16.3%	9.5%	11.2%	
1989	31.5%	17.6%	20.4%	17.5%	11.5%	11.8%	
1990	-3.2%	11.8%	13.1%	13.9%	11.2%	12.0%	
1991	30.6%	18.0%	15.4%	17.6%	11.9%	12.9%	
1992	7.7%	15.7%	15.9%	16.2%	11.3%	12.6%	
1993	10.0%	10.6%	14.5%	14.9%	12.8%	12.3%	
1994	1.3%	11.9%	8.7%	14.4%	14.6%	11.9%	
1995	37.4%	13.3%	16.6%	14.8%	14.6%	11.9%	
1996	23.1%	17.2%	15.2%	15.3%	14.6%	12.6%	
1997	33.4%	22.9%	20.2%	18.0%	16.6%	13.1%	
1998	28.6%	30.5%	24.1%	19.2%	17.7%	13.6%	
1999	21.0%	26.4%	28.6%	18.2%	17.9%	13.6%	
2000	-9.1%	17.2%	18.3%	17.5%	15.7%	12.8%	
2001	-11.9%	5.7%	10.7%	12.9%	15.2%	12.0%	
2002	-22.1%	-6.8%	-0.6%	9.3%	12.7%	11.1%	
2003	28.7%	-5.3%	-0.6%	11.1%	13.0%	11.7%	
2004	10.9%	-0.5%	-2.3%	12.1%	13.2%	10.9%	
2005	4.9%	3.9%	0.5%	9.1%	11.9%	10.4%	
2006	15.8%	14.7%	6.2%	8.4%	11.8%	10.6%	
2007	5.5%	9.2%	12.8%	5.9%	11.8%	11.0%	
2008	-37.0%	-5.2%	-2.2%	-1.4%	8.4%	9.2%	
2009	26.5%	-0.7%	0.4%	-0.9%	8.2%	9.4%	
2010	15.1%	-0.8%	2.3%	1.4%	9.1%	9.7%	
2011	2.1%	-1.6%	-0.3%	2.9%	7.8%	9.3%	
2012	16.0%	14.6%	1.7%	7.1%	8.2%	9.8%	
2013	32.4%	15.9%	17.9%	7.4%	9.2%	10.0%	
2014	13.7%	15.6%	15.5%	7.7%	9.8%	9.9%	
2015	1.4%	15.3%	12.6%	7.3%	8.2%	9.7%	
2016	12.0%	14.3%	14.7%	6.9%	7.7%	10.2%	
2017	21.8%	12.0%	15.8%	8.5%	7.2%	10.1%	
2018	-4.8%	7.1%	8.4%	13.1%	5.6%	9.8%	10.0%
Rolling periods w/ returns less than 14.77%		**58**	**61**	**61**	**64**	**44**	**1**
Rolling periods observed		**90**	**89**	**84**	**74**	**44**	**1**
Percent of periods less than 14.77%		**64.4%**	**68.5%**	**72.6%**	**86.5%**	**100.0%**	**100.0%**

MPSC Staff's Answer to ABATE's 1st Discovery Request
MPSC Case No. U-20561
November 20, 2019

Question:

7. Please identify all analyses Mr. Megginson has undertaken to assess the reasonableness of a projected annual market growth rate of 11.25% or 15.0%. If Mr. Megginson has not performed any analyses to assess the reasonableness of his assumed market growth rate, do so state.

Response:

Mr. Megginson did not undertake an analysis assessing the reasonableness of a projected annual market growth rate of 11.25% or 15.0%. Value Line analysts, in which Mr. Megginson derived his projected CAPM analysis, estimated that total market growth in a 3-5-year timeframe would be 60% as noted on Exhibit No. S-4, Schedule D-5, page 7 of 12. Value Line does not indicate how it annualizes its 3-5-year market growth forecast.

Respondent: Kirk Megginson

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-1.7]
Respondent:	B. Villadsen / Legal
Page:	1 of 1

Question: Please identify and provide all Commission Orders that explicitly relied on and accepted water and natural gas utilities as part of a proxy group to establish a fair rate of return for a vertically integrated electric utility in the continental United States.

Answer: The DTE Electric Company objects to providing the requested information for the reasons that the request is vague, overly broad, seeks excessive detail and is unduly burdensome. Subject to these objections, but without waiving them, please see as follows: I assume that the question refers to any commission rather than just the Michigan Public Service Commission and is asking about all commission orders of which I am aware. I am aware of multiple dockets in which a regulatory commission has considered a broad sample of regulated and unregulated companies in order to determine the rate of return for an electric utility. These dockets include A.19-04-014 before the California Public Utilities Commission and ER16-2632-000 before the Federal Energy Regulatory Commission. Also, prior dockets before the Michigan Public Service Commission have included combination electric and gas utilities in the proxy groups. See, for example, U-20162. Other jurisdictions outside of the continental United States also rely on proxy groups comprised of multiple regulated utilities, including water and natural gas companies. See, for example, Decision 22570-D01-2018 in Alberta's Generic Cost of Capital. I also note that commissions have considered non-water companies in the proxy groups in order to establish the fair rate of return for water utilities. See, for example, Arizona Docket No. W-01303A-08-0227 and NM Case No. 08-00134-UT. Based solely on the continental United States, I am not aware of a specific commission order that explicitly accepted such a proxy group. Neither has the Arizona, California, or New Mexico commissions rejected my use of alternate industry samples.

Attachments: *None*

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-11.87a]
Respondent:	E. J. Solomon
Page:	1 of 1

Question: At pages 3-4 of his Rebuttal testimony, Mr. Solomon states that the "incremental proforma impact of S&P's FFO to debt calculation will be a reduction of ~0.5%. The credit agencies would view this reduction in credit metrics as a weakening of the financial integrity of the Company." Please respond to the following:

a. Please confirm S&P's financial risk rating of DTE Electric is "Significant." If this cannot be confirmed, please provide a detailed explanation with all supporting documents and analysis.

Answer: Yes. S&P's financial risk profile for DTE Electric is "Significant".

Attachments: *None*

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-11.87b]
Respondent:	E. J. Solomon
Page:	1 of 1

Question: At pages 3-4 of his Rebuttal testimony, Mr. Solomon states that the "incremental proforma impact of S&P's FFO to debt calculation will be a reduction of ~0.5%. The credit agencies would view this reduction in credit metrics as a weakening of the financial integrity of the Company." Please respond to the following:

b. Please confirm DTE Electric's credit metrics are assessed using S&P's medial volatility matrix. If this cannot be confirmed, please provide a detailed explanation with all supporting documents and analysis.

Answer: Yes. DTE Electric's credit metrics are assessed using S&P's medial volatility matrix.

Attachments: *None*

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-11.87c]
Respondent:	E. J. Solomon
Page:	1 of 1

Question: At pages 3-4 of his Rebuttal testimony, Mr. Solomon states that the "incremental proforma impact of S&P's FFO to debt calculation will be a reduction of ~0.5%. The credit agencies would view this reduction in credit metrics as a weakening of the financial integrity of the Company." Please respond to the following:

c. Please confirm S&P's benchmark range for the FFO-to-Debt ratio assessed under the medial volatility matrix with a "significant" financial risk rating is 13% - 23%. If this cannot be confirmed, please provide a detailed explanation with all supporting documents and analysis.

Answer: We can confirm S&P's benchmark range for the FFO-to-Debt ratio assessed under the medial volatility matrix with a "significant" financial risk rating is 13% - 23%.

Attachments: *none*

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-11.87d]
Respondent:	E. J. Solomon
Page:	1 of 1

Question: At pages 3-4 of his Rebuttal testimony, Mr. Solomon states that the "incremental proforma impact of S&P's FFO to debt calculation will be a reduction of ~0.5%. The credit agencies would view this reduction in credit metrics as a weakening of the financial integrity of the Company." Please respond to the following:

d. Please confirm that S&P's base case forecasted FFO-to-Debt for DTE Electric is 19% to 21%. If this cannot be confirmed, please provide a detailed explanation with all supporting documents and analysis.

Answer: We can confirm S&P's base case forecasted FFO-to-Debt for DTE Electric is 19% to 21% per the August 27, 2019 S&P Research Update. In the March 12, 2019 S&P Research Update S&P forecasted 2020 FFO-to-Debt of 18% to 20%.

Attachments: *none*

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-11.87e]
Respondent:	E. J. Solomon
Page:	1 of 1

Question: At pages 3-4 of his Rebuttal testimony, Mr. Solomon states that the "incremental proforma impact of S&P's FFO to debt calculation will be a reduction of ~0.5%. The credit agencies would view this reduction in credit metrics as a weakening of the financial integrity of the Company." Please respond to the following:

e. Please confirm that, if DTE Electric's forecasted FFO-to-Debt ratio declined by 0.5% as Mr. Solomon states it will, the resulting proforma FFO- to-Debt will then be approximately 18.5% to 20.5%. If this cannot be confirmed, please provide a detailed explanation with all supporting documents and analysis.

Answer: We can confirm that the 0.5% decline will impact the August 27, 2019 proforma FFO-to-Debt to 18.5% to 20.5% and will impact the March 12, 2019 proforma 2020 FFO-to-Debt to 17.5% to 19.5%.

Attachments: *none*

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-11.87f]
Respondent:	E. J. Solomon
Page:	1 of 1

Question: At pages 3-4 of his Rebuttal testimony, Mr. Solomon states that the "incremental proforma impact of S&P's FFO to debt calculation will be a reduction of ~0.5%. The credit agencies would view this reduction in credit metrics as a weakening of the financial integrity of the Company." Please respond to the following:

f. Please confirm that an FFO-to-Debt ratio of 18.5% to 20.5% is 5.5% to 7.5% above the low-end of the benchmark range (13% to 23%) identified in subpart (c) above. If this cannot be confirmed, please provide a detailed explanation with all supporting documents and analysis.

Answer: In the August 27, 2019 Research Update, S&P states, "We could lower our rating on DTE Electric over the next 24 months if DTE Electric's stand-alone financial metrics weaken such that its FFO to debt remains consistently below 15%."

Attachments: *none*

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-11.87g]
Respondent:	E. J. Solomon
Page:	1 of 1

Question: At pages 3-4 of his Rebuttal testimony, Mr. Solomon states that the "incremental proforma impact of S&P's FFO to debt calculation will be a reduction of ~0.5%. The credit agencies would view this reduction in credit metrics as a weakening of the financial integrity of the Company." Please respond to the following:

g. Please confirm that an FFO-to-Debt ratio of 18.5% to 20.5% is 0.5% to 2.5% above the midpoint (18.0%) of the benchmark range identified in subpart (c) above. If this cannot be confirmed, please provide a detailed explanation with all supporting documents and analysis.

Answer: We can confirm the midpoint at 18% based on the August 27, 2019 report with the downgrade trigger at 15% and the upgrade trigger at 21%.

Attachments: *none*

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-11.87h]
Respondent:	E. J. Solomon
Page:	1 of 1

Question: At pages 3-4 of his Rebuttal testimony, Mr. Solomon states that the "incremental proforma impact of S&P's FFO to debt calculation will be a reduction of ~0.5%. The credit agencies would view this reduction in credit metrics as a weakening of the financial integrity of the Company." Please respond to the following:

h. Please provide the FFO-to-Debt level that must be sustained by DTE Electric in order to trigger a credit rating downgrade that was provided in the "Downside scenario" identified by S&P in its August 27, 2019 Research Update titled "Research Update: DTE Electric Co. And DTE Gas Co. Long-Term ICRs Raised To 'A-', Ratings Off UCO On Updated Group Rating Methodology."

Answer: See response to ABDE-11.87f.

Attachments: *none*

MPSC Case No.: U-20561
Requestor: ABATE
Question No.: ABDE-11.87i]
Respondent: E. J. Solomon
Page: 1 of 1

Question: At pages 3-4 of his Rebuttal testimony, Mr. Solomon states that the “incremental proforma impact of S&P’s FFO to debt calculation will be a reduction of ~0.5%. The credit agencies would view this reduction in credit metrics as a weakening of the financial integrity of the Company.” Please respond to the following:

i. Admit that, should DTE Electric’s FFO-to-Debt reach the 18.5% to 20.5% levels identified in subparts (e), (f), and (g) above, exceeds the level of FFO-to-Debt that would trigger a ratings downgrade as identified by S&P.

Answer: Financial metrics are only one criterion that S&P uses to determine ratings. S&P could also lower DTE Electric’s ratings if business risk materially rises as a result of weaker regulatory support. Although a decline in DTE Electric’s FFO-to-Debt of 0.5% may not be material in itself to lower our credit ratings, the reduction in FFO-to-Debt as a result of regulatory actions will be viewed negatively by the rating agencies.

Attachments: *none*

MPSC Case No.: U-20561
Requestor: ABATE
Question No.: ABDE-5.62a-d]
Respondent: T. M. Uzenski
Page: 1 of 2

Question: Please provide a list of all Industry Associations to which the Company has made a direct or indirect Contribution in the last five (5) years. For each and every separate direct or indirect Contribution, please identify the following:
(a) The date made;
(b) The amount;
(c) The Industry Association to which it was made; and
(d) An explanation of whether the Contribution was included in the Company's revenue requirement and whether the Company sought recovery of the Contribution from customers or ratepayers.

Answer:

Description	2018	2017	2016	1/ 2015	2014	2013
Corporate Memberships Charged to Operating Expense						
American Coal Ash Association	15	15	-		-	-
American Society of Employers	13	12	-		-	-
CGS Advisors	-	186	-		-	-
Conference Board Inc	157	52	95		69	-
Electric Power Research Institute (EPRI)	1,620	5,637	4,903		5,790	3,003
Edison Electric Institute	1,767	1,269	690		1,657	433
Gartner Group	111	73	155		-	-
HR Policy Association	26	26	-		-	-
HR Services	75	18	-		-	-
Institute of Nuclear Power	1,347	1,333	1,353		1,345	1,303
Institute of Public Utilities	40	8	-		-	-
The Corporate Executive Board	80	446	107		324	-
Michigan Electric & Gas Association	52	19	33		41	-
National Safety Council	35	398	74		343	-
North American Electric Reliability	2,730	1,425	191		166	-
Nuclear Energy Institute Inc 2/	602	649	578		612	527
US Nuclear Regulatory Commission 2/	6,730	6,928	7,350		7,859	6,710
Other Allowable Corporate Memberships	64	-	31		33	17
Other Corp Memberships excluded from Rev Requirement	**1,041**	**554**	**682**		**758**	**1,190**
Total Corporate Memberships	16,506	19,048	16,242		18,996	13,183
Corp Memberships included in Rev Requirement	**15,465**	**18,494**	**15,560**		**18,238**	**11,993**
Rate Case Filing	U-20561	U-20162	U-18255		U-18104	U-17767

1/ 2015 was not a historical test year for any previous rate case

2/ prior to 2018 included as part of Nuclear Power Generation O&M workpaper of rate case filings

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-5.62a-d]
Respondent:	T. M. Uzenski
Page:	2 of 2

The portion of Edison Electric Institute dues related to lobbying activities is recorded to a FERC account that is excluded from base rates. The Company has not sought recovery of that portion.

Attachments: None.

MPSC Case No.: U-20561
Requestor: ABATE
Question No.: ABDE-5.63a-d]
Respondent: T. M. Uzenski
Page: 1 of 1

Question: Please provide a list of all Charitable Organizations to which the Company has made a direct or indirect Contribution in the last five (5) years. For each and every separate direct or indirect Contribution, please identify the following:

(a) The date made;
(b) The amount;
(c) The Charitable Organization to which it was made; and
(d) An explanation of whether the Contribution was included in the Company's revenue requirement and whether the Company sought recovery of the Contribution from customers or ratepayers.

Answer: Charitable contributions are not included in the revenue requirement and the Company did not request recovery through customer rates. Charitable contributions are recorded in a FERC account that is excluded from rates. Charitable donations and corporate sponsorships for the last five years were as follows:

.

Year	Amount
2018	$ 2,811,852
2017	$10,029,908
2016	$ 4,662,950
2015	$ 2,824,675
2014	$ 2,279,343

Attachments: None.

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-5.64a-d]
Respondent:	T. M. Uzenski
Page:	1 of 1

Question: Please provide a list of all Social Welfare Organizations to which the Company has made a direct or indirect Contribution in the last five (5) years. For each and every separate direct or indirect Contribution, please identify the following:

(a) The date made;
(b) The amount;
(c) The Social Welfare Organization to which it was made; and
(d) An explanation of whether the Contribution was included in the Company's revenue requirement and whether the Company sought recovery of the Contribution from customers or ratepayers.

Answer: Contributions to social welfare organizations are not included in the revenue requirement and the Company did not request recovery through customer rates. Such contributions are recorded in a FERC account that is excluded from rates. See question ABDE 5.66.

Attachments: None.

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-5.65]
Respondent:	T. M. Uzenski
Page:	1 of 1

Question: To the extent not included in response to Interrogatory Nos. 62-64, please provide a list of all non-profit or tax exempt organizations to which the Company has made a direct or indirect Contribution in the last five (5) years. For each and every separate direct or indirect Contribution, please identify the following:

(a) The date made;
(b) The amount;
(c) The organization to which it was made; and
(d) An explanation of whether the Contribution was included in the Company's revenue requirement and whether the Company sought recovery of the Contribution from customers or ratepayers.

Answer: All such costs have been included in response to questions 62, 63, and 66.

Attachments: None.

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-5.66a-d]
Respondent:	T. M. Uzenski
Page:	1 of 1

Question: Please provide a list of all political or governmental affairs consultants or organizations to which the Company has made a direct or indirect Contribution in the last five (5) years. For each and every separate direct or indirect Contribution, please identify the following:

(a) The date made;
(b) The amount;
(c) The consultant or organization to which it was made; and
(d) An explanation of whether the Contribution was included in the Company's revenue requirement and whether the Company sought recovery of the Contribution from customers or ratepayers.

Answer: Contributions to political organizations and consultant fees related to political activities are recorded to a FERC account that is excluded from rates. The Company has not sought recovery of such costs through customer rates. The amounts below include all civic and political contributions and expenses (including contributions to social welfare organizations).

Year	Amount
2018	$3,779,536
2017	$3,118,339
2016	$2,779,926
2015	$3,237,991
2014	$4,942,858

Attachments: None.

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-11.88]
Respondent:	T. M. Uzenski
Page:	1 of 1

Question: See ABDE-5.62a-d. In 2018, DTE recorded $64,000 for "Other Allowable Corporate Memberships." Please identify each membership that is included in this category and indicate the cost associated with each.

Answer:

($000)	
Midwest Energy Efficiency Alliance	$52
Nuclear Procurement Issues Corporation (NUPIC)	8
American Gas Association (included in error)	4
Total Other Allowable Corporate Memberships	$64

Attachments: *None.*

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-11.89]
Respondent:	T. M. Uzenski
Page:	1 of 1

Question: See ABDE-10.80. Please identify the specific accounts that are included in Ms. Uzenski's reference to "other O&M accounts." Please include a list of all expenses charged to each of these accounts for the previous five years.

Answer: Other O&M accounts that include membership expenses are 501, 506, 514, 518, 520, 524, 580, 586, 908, 921, 923, 928 and 930.2. Please see response to question ABDE-11.91.

Attachments: none

MPSC Case No.: U-20561
Requestor: ABATE
Question No.: ABDE-11.90a]
Respondent: T. M. Uzenski
Page: 1 of 1

Question: See ABDE-10.79. The Edison Electric Institute (EEI) identifies the portion of dues that relate to influencing legislation on its invoices to DTE. That portion is recorded to account 426.4 which is excluded from base rates.

a. Please provide copies of all EEI invoices received by DTE over the previous five years.

Answer: See attached invoices.

Attachments:

U-20561 ABDE-11.90a 2015 EEI Membership Dues Invoice 12-2-2014.pdf
U-20561 ABDE-11.90a 2016 EEI Membership Dues Invoice 12-8-2015.pdf
U-20561 ABDE-11.90a 2017 EEI Membership Dues Invoice 12-7-2016.pdf
U-20561 ABDE-11.90a 2018 EEI Membership Dues Invoice 12-13-2017.pdf
U-20561 ABDE-11.90a 2019 EEI Membership Dues Invoice 12-10-2018.pdf

Edison Electric Institute
Power by Association℠
701 Pennsylvania Avenue, N.W. ■ Washington, D.C. 20004-2696 ■ Phone (202) 508-5000

Invoice for Membership Dues

Mr. Gerard M. Anderson
Chairman & CEO
DTE Energy Co
One Energy Plaza
Detroit, MI 48226-1221

Date	Invoice Number
12/02/2014	DUES201516

Payment due on or before 1/30/2015

Description	Total
2015 EEI Membership Dues for:	
Regular Activities of Edison Electric Institute [1]	$1,124,396
Industry Issues [2]	112,440
Restoration, Operations, and Crisis Management Program [3]	15,000
2015 Contribution to The Edison Foundation, which funds IEI [4]	30,000
Total	**$1,281,836**

1 The portion of 2015 membership dues relating to influencing legislation, which is not deductible for federal income tax purposes, is estimated to be 13%.

2 The portion of the 2015 industry issues support relating to influencing legislation is estimated to be 25%.

3 The Restoration, Operations, and Crisis Management Program is related to improvements to industry–wide responses to major outages (e.g. National Response Event); continuity of industry and business operations; and EEI's all hazards support and coordination of the industry during times of crises. No portion of this assessment is allocable to influencing legislation.

4 The Edison Foundation is an IRC 501(c)(3) educational and charitable organization. Contributions are deductible for federal income tax purpose to the extent provided by law. Please consult your tax advisor with respect to your specific situation.

PLEASE NOTE INFORMATION FOR ELECTRONIC PAYMENT

The following instructions should be used when transferring funds electronically (ACH or wire) to Edison Electric Institute:

Beneficiary's Bank:	Wells Fargo Bank, N.A.
Bank's Address:	Washington, DC
Bank's ABA Number:	121000248
Beneficiary:	Edison Electric Institute
Beneficiary's Acct No:	2 0 0 0 0 1 3 8 4 2 8 9 7
Beneficiary's Address:	701 Pennsylvania Avenue, NW Washington, DC 20004-2696 USA
Beneficiary Reference:	2015 Membership Dues

Please refer any questions to Terri Oliva, EEI Controller: (202) 508-5541 *or* memberdues@eei.org

Edison Electric Institute
Power by Association℠
701 Pennsylvania Avenue, N.W. ■ Washington, D.C. 20004-2696 ■ Phone (202) 508-5000

Invoice for Membership Dues

MR. GERARD M. ANDERSON
CHAIRMAN & CEO
DTE ENERGY COMPANY
ONE ENERGY PLAZA
DETROIT, MI 48226-1221

Date	Invoice Number
12/08/2015	DUES201617

Payment due on or before 1/29/2016

Description	Total
2016 EEI Membership Dues for:	
Regular Activities of Edison Electric Institute [1]	$1,141,110
Industry Issues [2]	114,111
Restoration, Operations, and Crisis Management Program [3]	15,000
2016 Contribution to The Edison Foundation, which funds IEI [4]	30,000
Total	**$1,300,221**

1 The portion of 2016 membership dues relating to influencing legislation, which is not deductible for federal income tax purposes, is estimated to be 13%.

2 The portion of the 2016 industry issues support relating to influencing legislation is estimated to be 26%.

3 The Restoration, Operations, and Crisis Management Program is related to improvements to industry–wide responses to major outages (e.g. National Response Event); continuity of industry and business operations; and EEI's all hazards support and coordination of the industry during times of crises. No portion of this assessment is allocable to influencing legislation.

4 The Edison Foundation is an IRC 501(c)(3) educational and charitable organization. Contributions are deductible for federal income tax purpose to the extent provided by law. Please consult your tax advisor with respect to your specific situation.

PLEASE NOTE INFORMATION FOR ELECTRONIC PAYMENT

The following instructions should be used when transferring funds electronically (ACH or wire) to Edison Electric Institute:

Beneficiary's Bank:	Wells Fargo Bank, N.A.
Bank's Address:	Washington, DC
Bank's ABA Number:	121000248
Beneficiary:	Edison Electric Institute
Beneficiary's Acct No:	2 0 0 0 0 1 3 8 4 2 8 9 7
Beneficiary's Address:	701 Pennsylvania Avenue, NW Washington, DC 20004-2696 USA
Beneficiary Reference:	2015 Membership Dues

Please refer any questions to Terri Oliva, EEI Controller: (202) 508-5541 *or* memberdues@eei.org

I/O-20000054090
~~GL-518006~~ Prepaid-102020
Amount - $1,132,490.00

Invoice for Membership Dues

I/O-20000058561
GL-561700
Amount - $183,292.02

I/O-20000051772 GL-561500
Amount-$30,000

Vendor- 200925
Co Code - 0388

EEI
Edison Electric INSTITUTE

MR. GERARD M. ANDERSON
CHAIRMAN & CEO
DTE ENERGY COMPANY
ONE ENERGY PLAZA
DETROIT, MI 48226-1221

Date	Invoice Number
12/07/2016	DUES201717

Payment due on or before 1/31/2017

Description	Total
2017 EEI Membership Dues for:	
Regular Activities of Edison Electric Institute [1]	$1,182,529
Industry Issues [2]	118,253
Restoration, Operations, and Crisis Management Program [3]	15,000
2017 Contribution to The Edison Foundation, which funds IEI [4]	30,000
Total	**$1,345,782**

1 The portion of 2017 membership dues relating to influencing legislation, which is not deductible for federal income tax purposes, is estimated to be 13%. 153,728.77

2 The portion of the 2017 industry issues support relating to influencing legislation is estimated to be 25%. 29,563.25

3 The Restoration, Operations, and Crisis Management Program is related to improvements to industry–wide responses to major outages (e.g. National Response Event); continuity of industry and business operations; and EEI's all hazards (storms, cyber, etc.) support and coordination of the industry during times of crises. No portion of this assessment is allocable to influencing legislation.

4 The Edison Foundation is an IRC 501(c)(3) educational and charitable organization. Contributions are deductible for federal income tax purposes to the extent provided by law. Please consult your tax advisor with respect to your specific situation. 30,000

PLEASE NOTE INFORMATION FOR ELECTRONIC PAYMENT

The following instructions should be used when transferring funds electronically (ACH or wire) to Edison Electric Institute:

Beneficiary's Bank:	Wells Fargo Bank, N.A.
Bank's Address:	Washington, DC
Bank's ABA Number:	121000248
Beneficiary:	Edison Electric Institute
Beneficiary's Acct No:	2000013842897
Beneficiary's Address:	701 Pennsylvania Avenue, NW Washington, DC 20004-2696 USA
Beneficiary Reference:	2017 Membership Dues

Lobbying 183,292.02
I/O 20000058561

Donations 30,000
I/O-20000051772

Dues - 1,132,490.00
20000054090

Please refer any questions to Terri Oliva, EEI Controller: (202) 508-5541 *or* memberdues@eei.org

Prepaid -102020 V-200925 Co Code-0388 20000000054090 $1,165,315.40

Invoice for Membership Dues

$30,000 to Co Code 0388/GL561500 20000000051772

$187,260.60 -0388/200000005856 1 GL-561700

EEI Edison Electric INSTITUTE

MR. GERARD M. ANDERSON
CHAIRMAN & CEO
DTE ENERGY COMPANY
ONE ENERGY PLAZA
DETROIT, MI 48226-1221

Date	Invoice Number
12/13/2017	DUES201818

Payment due on or before 1/31/2018

Description	Total
2018 EEI Membership Dues for:	
Regular Activities of Edison Electric Institute [1] – $158,077.14	$1,215,978
Industry Issues [2]	121,598
Restoration, Operations, and Crisis Management Program [3] 29,183.52	15,000
2018 Contribution to The Edison Foundation, which funds IEI [4] 20000005M72	30,000
Total	**$1,382,576**

1 The portion of 2018 membership dues relating to influencing legislation, which is not deductible for federal income tax purposes, is estimated to be 13%.

2 The portion of the 2018 industry issues support relating to influencing legislation is estimated to be 24%. 200000058561

3 The Restoration, Operations, and Crisis Management Program is related to improvements to industry–wide responses to major outages (e.g. National Response Event); continuity of industry and business operations; and EEI's all hazards (storms, cyber, etc.) support and coordination of the industry during times of crises. No portion of this assessment is allocable to influencing legislation.

4 The Edison Foundation is an IRC 501(c)(3) educational and charitable organization. Contributions are deductible for federal income tax purposes to the extent provided by law. Please consult your tax advisor with respect to your specific situation.

PLEASE NOTE INFORMATION FOR ELECTRONIC PAYMENT

The following instructions should be used when transferring funds electronically (ACH or wire) to Edison Electric Institute:

Beneficiary's Bank:	Wells Fargo Bank, N.A.
Bank's Address:	Washington, DC
Bank's ABA Number:	121000248
Beneficiary:	Edison Electric Institute
Beneficiary's Acct No:	2000013842897
Beneficiary's Address:	701 Pennsylvania Avenue, NW Washington, DC 20004-2696 USA
Beneficiary Reference:	2018 Membership Dues

30,000 Donation
GL-561500 20000000051772
187,260.60 Lobbying
GL-561700 200000058561
1,165,315.40
GL-102020 20000000054090

Please refer any questions to Terri Oliva, EEI Controller: (202) 508-5541 *or* memberdues@eei.org

Invoice for Membership Dues

Edison Electric INSTITUTE

MR. GERARD M. ANDERSON
CHAIRMAN & CEO
DTE ENERGY
ONE ENERGY PLAZA
DETROIT, MI 48226-1221

Date	Invoice Number
12/10/2018	DUES201918

Payment due on or before 1/31/2019

Description		Total
2019 EEI Membership Dues for:		
Regular Activities of Edison Electric Institute [1]	B	$1,236,186 C
Industry Issues [2]	✓	123,619
Restoration, Operations, and Crisis Management Program [3]	PY	15,000
2019 Contribution to The Edison Foundation, which funds IEI [4]	⊥	30,000 D
Total		**$1,404,805**

1 The portion of 2019 membership dues relating to influencing legislation, which is not deductible for federal income tax purposes, is estimated to be 13%.

2 The portion of the 2019 industry issues support relating to influencing legislation is estimated to be 24%.

3 The Restoration, Operations, and Crisis Management Program is related to improvements to industry–wide responses to major outages (e.g. National Response Event); continuity of industry and business operations; and EEI's all hazards (storms, cyber, etc.) support and coordination of the industry during times of crises. No portion of this assessment is allocable to influencing legislation.

4 The Edison Foundation is an IRC 501(c)(3) educational and charitable organization. Contributions are deductible for federal income tax purposes to the extent provided by law. Please consult your tax advisor with respect to your specific situation.

PLEASE NOTE INFORMATION FOR ELECTRONIC PAYMENT

The following instructions should be used when transferring funds electronically (ACH or wire) to Edison Electric Institute:

Beneficiary's Bank:	Wells Fargo Bank, N.A.
Bank's Address:	Washington, DC
Bank's ABA Number:	121000248
Beneficiary:	Edison Electric Institute
Beneficiary's Acct No:	2000013842897
Beneficiary's Address:	701 Pennsylvania Avenue, NW Washington, DC 20004-2696 USA
Beneficiary Reference:	2019 Membership Dues

✓ – materially consistent w/ PY

PY – agreed to PY

Please refer any questions to Terri Oliva, EEI Assistant Treasurer: (202) 508-5541 *or* memberdues@eei.org

A

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-11.90b]
Respondent:	T. M. Uzenski
Page:	1 of 1

Question: See ABDE-10.79. The Edison Electric Institute (EEI) identifies the portion of dues that relate to influencing legislation on its invoices to DTE. That portion is recorded to account 426.4 which is excluded from base rates.

b. Please explain why DTE records the portion of dues that relate to influencing legislation to account 426.4, which is excluded from base rates.

Answer: This is required by the Electric Uniform System of Accounts which states:

> *"This account shall include expenditures for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation, or ordinances (either with respect to the possible adoption of new referenda, legislation or ordinances or repeal or modification of existing referenda, legislation or ordinances) or approval, modification, or revocation of franchises; or for the purpose of influencing the decisions of public officials, but shall not include such expenditures which are directly related to appearances before regulatory or other governmental bodies in connection with the reporting utility's existing or proposed operations."*

Attachments: *None.*

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-11.90c]
Respondent:	T. M. Uzenski
Page:	1 of 1

Question: See ABDE-10.79. The Edison Electric Institute (EEI) identifies the portion of dues that relate to influencing legislation on its invoices to DTE. That portion is recorded to account 426.4 which is excluded from base rates.

c. Please indicate which of the other industry associations listed in ABDE-5.62a-d similarly identifies the portion of dues that relate to influencing legislation on its invoices to DTE.

Answer: None of the other industry association invoices similarly identify the portion of dues that relate to influencing legislation.

Attachments: *None.*

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-11.90d]
Respondent:	T. M. Uzenski
Page:	1 of 1

Question: See ABDE-10.79. The Edison Electric Institute (EEI) identifies the portion of dues that relate to influencing legislation on its invoices to DTE. That portion is recorded to account 426.4 which is excluded from base rates.

d. Please provide copies of the invoices received by DTE over the previous five years for each industry associations identified in the preceding question. If no industry associations are identified, please indicate whether any of the industry associations listed in ABDE- 5.62a-d seek to influence legislation or regulatory matters.

Answer: None were identified in the previous question. However, when researching these questions, the Company identified an error in our filing. An additional amount of $281,175 should have been removed from the revenue requirement and reflected on line 27 of Exhibit A-3, Schedule C14. This changes the total disallowed memberships from $1.041M to $1.322M.

Attachments: *None*

MPSC Case No.:	U-20561
Requestor:	ABATE
Question No.:	ABDE-11.91]
Respondent:	T. M. Uzenski
Page:	1 of 1

Question: See ABDE-5.62a-d. In 2018, DTE included $15,465,00 in Corporate Memberships in rates. In response to a subsequent discovery request, DTE states that the "items listed in ABDE-5.62 are recorded to account 930.2, Miscellaneous General Expense, and other O&M accounts." Please provide a breakdown of the costs included in each of these accounts for the previous five years.

Answer: Please see file attached.

Attachments: *U-20561 ABDE 11.91 Memberships by Account.pdf*

Michigan Public Service Commission
DTE Electric Company
Historical Corporate Memberships Adjustment
2013-2014, 2016-2018
Discovery Request: U-20561 ABDE-11.89
($000)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
Line No.	**Description**	**2018 FERC Account**	**2018**	**2017 FERC Account**	**2017**	**2016 FERC Account**	**2016**	**1/ 2015**	**2014 FERC Account**	**2014**	**2013 FERC Account**	**2013**
1	**Corporate Memberships Charged to Operating Expense**											
2	American Coal Ash Association	501	15	501	15		-			-		-
3	American Society of Employers	930.2	13	930.2	12		-			-		-
4	CGS Advisors		-	930.2	186		-			-		-
5	Conference Board Inc	930.2, 506, 921	157	930.2 & 506	52	930.2 & 506	95		930.2 & 506	69		-
6	Electric Power Research Institute (EPRI)	524	1,620	524, 506 & 107	5,637	524, 506 & 107	4,903		506, 518, 524, 580, 107	5,790	514, 524, 580, 506	3,003
7	Edison Electric Institute	921 & 506	1,486	921 & 506	1,269	921 & 506	690		921 & 506	1,657	923	433
8	Gartner Group	921	111	921	73	921	155			-		-
9	HR Policy Association	930.2	26	930.2	26		-			-		-
10	HR Services	930.2	75	930.2	18		-			-		-
11	Institute of Nuclear Power	524	1,347	524	1,333	524	1,353		524	1,345	524	1,303
12	Institute of Public Utilities	921	40	921	8		-			-		-
13	The Corporate Executive Board	921	80	921	446	930.2 & 921	107		930.2 & 921	324		-
14	Michigan Electric & Gas Association	921	52	921	19	921	33		921	41		-
15	National Safety Council	930.2	35	921, 520, 514	398	930.2, 586	74		923.0	343		-
16	North American Electric Reliability	930.2 & 580	2,730	930.2 & 580	1,425	930.2 & 580	191		930.2 & 580	166		-
17	Nuclear Energy Institute Inc	580	602	524	649	524	578		524	612	524	527
18	US Nuclear Regulatory Commission	580	6,730	524	6,928	524	7,350		524	7,859	524	6,710
19	Other Allowable Corporate Memberships	930.2 & 908	64		-	930.2	31		580 & 506	33	928	17
20	**Other Corp Memberships excluded from Rev Requirement - corrected**		**1,322**		554		682			758		1,190
21	Total Corporate Memberships		16,506		19,048		16,242			18,996		13,183
	Other Corp Memberships excluded from Rev Requirement - as filed		**1,041**									

1/ 2015 was not a historical test year for any previous rate case

MPSC Case No.: U-20561
Requestor: ABATE
Question No.: ABDE-11.92a]
Respondent: T. M. Uzenski
Page: 1 of 1

Question: See page 335 of DTE's 2018 FERC Form No. 1 (excerpt provided below):

Name of Respondent DTE Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Board of Director's Expense	2,145,195
7	Customer Service Expense	281,841
8	Environmental Remediation Costs	4,031,257
9	Learning & Technical Development Program Expense	606,607
10	Membership & Dues	969,064
11	Office Upgrades & Repairs Expense	457,621
12	Other Management Services	509,462
13	Recruiting Expense	257,602
14	Shareholder Services Costs	492,464
15	Travel Expense	198,616

a. Please explain why DTE did not include any expenses for "Industry Association Dues" in account 930.2, Miscellaneous General Expense.

Answer: Industry association dues recorded in account 930.2 are included in the Membership & Dues line. (Line 10.) See attachment provided in ABDE-11.92c.

Attachments: N/A

MPSC Case No.: U-20561
Requestor: ABATE
Question No.: ABDE-11.92b]
Respondent: T. M. Uzenski
Page: 1 of 1

Question: See page 335 of DTE's 2018 FERC Form No. 1 (excerpt provided below):

Name of Respondent DTE Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Board of Director's Expense	2,145,195
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8	Environmental Remediation Costs	4,031,257
9	Learning & Technical Development Program Expense	606,607
10	Membership & Dues	969,064
11	Office Upgrades & Repairs Expense	457,621
12	Other Management Services	509,462
13	Recruiting Expense	257,602
14	Shareholder Services Costs	492,464
15	Travel Expense	198,616

b. Please indicate whether DTE has included expenses for "Industry Association Dues" in account 930.2, Miscellaneous General Expense, over the previous five years.

Answer: Industry association dues recorded in account 930.2 are included in the Membership & Dues line. (Line 10.)

Attachments: N/A

MPSC Case No.: U-20561
Requestor: ABATE
Question No.: ABDE-11.92c]
Respondent: T. M. Uzenski
Page: 1 of 1

Question: See page 335 of DTE's 2018 FERC Form No. 1 (excerpt provided below):

Name of Respondent DTE Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Board of Director's Expense	2,145,195
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9	Learning & Technical Development Program Expense	606,607
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12	Other Management Services	509,462
13	Recruiting Expense	257,602
14	Shareholder Services Costs	492,464
15	Travel Expense	198,616

c. Please identify the specific memberships that are included in the $969,064 recorded as "Membership & Dues" on line 10.

Answer: Please see attached.

Attachments: *U-20561 ABDE-11.92c Memberships_Dues Line 10 page 335 P-521.pdf*

Michigan Public Service Commission
DTE Electric Company
For The Period Ending 12/31/2018

Case No.: U-20561
Discovery Request: ABDE-11.92c
Data of Request: December 4, 2019
Witness: T. M. Uzenski

Memberships & Dues on Line 10 of Page 335 of 2018 P-521

Description	Amount
AMERICAN SOCIETY OF EMPLOYERS	7,427
CONFERENCE BOARD INC	74,345
HR POLICY ASSOCIATION	26,021
HR SERVICES (Bersin by Deloitte, Neuro Leadership Institute, Human Capital Institute)	74,718
NATIONAL SAFETY COUNCIL	34,904
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION (NERC)	132,900
NUCLEAR PROCUREMENT ISSUES CORPORATION (NUPIC)	8,442
SUBTOTAL ALLOWABLE INDUSTRY ASSOCIATION DUES	358,756
ALPENA AREA CHAMBER OF COMMERCE	1,026
ANN ARBOR YPSILANTI REGIONAL CHAMBER OF COMMERCE	1,026
BOARDVANTAGE INC	26,371
CADILLAC AREA CHAMBER OF COMMERCE	1,916
CENTER FOR WORKPLACE COMPLIANCE	8,804
CHAMBER OF COMMERCE OF THE USA	80,037
COUNTRY CLUB OF LANSING	1,344
CT CORP SYSTEM	15,239
DEARBORN CHAMBER OF COMMERCE	1,026
DELTA COUNTY CHAMBER OF COMMERCE	821
DETROIT REGIONAL CHAMBER OF COMMERCE	50,263
GREATER ROMEO WASHINGTON CHAMBER OF COMMERCE	465
HOWELL AREA CHAMBER OF COMMERCE	499
LENAWEE CHAMBER FOUNDATION	3,421
LIVONIA CHAMBER OF COMMERCE OF COMMERCE	512
MACOMB COUNTY CHAMBER OF COMMERCE	1,505
MANISTEE AREA CHAMBER OF COMMERCE	582
MICHIGAN CHAMBER OF COMMERCE	88,041
MICHIGAN COMMUNITY ASSOCIATIONS INSTITUTE	1,465
MICHIGAN MANUFACTURERS ASSOCIATION	25,968
MILAN CHAMBER OF COMMERCE	373
MONEY MEDIA INC	14,711
MUSKEGON LAKESHORE CHAMBER OF COMMERCE	900
NATIONAL ASSOCIATION OF EMPLOYEE CONCERNS (NAECP)	600
NATIONAL ASSOCIATION OF MANUFACTURE	93,851
NORTHERN STATES POWER COMPANY	8,004
OTHER MISC EXPENSES	118,420
PUBLIC AFFAIRS COUNCIL	7,924
SAGINAW COUNTY CHAMBER OF COMMERCE	388
SALINE AREA CHAMBER OF COMMERCE	513
SMALL BUSINESS ASSOCIATION OF MICHIGAN	4,002
SOFTWARE NETWORK USERS GROUP (SNUG)	500
SOUTHERN WAYNE COUNTY REGIONAL CHAMBER OF COMMERCE	787
STERLING HEIGHTS REGIONAL CHAMBER OF COMMERCE	411
THE ENGINEERING SOCIETY OF DETROIT	9,259
THE MONROE COUNTY CHAMBER OF COMMERCE	1,416
TRAVERSE CITY AREA CHAMBER OF COMMERCE	12,062
TROY CHAMBER OF COMMERCE	476
WOLTERS KLUWER	24,969
WYOMING KENTWOOD AREA CHAMBER OF COMMERCE	411
SUBTOTAL OTHER MEMBERSHIPS & DUES	610,308
TOTAL MEMBERSHIPS & DUES - ACCOUNT 930.2	**969,064**

MPSC Case No.: U-20561
Requestor: ABATE
Question No.: ABDE-3.21e]
Respondent: T. M. Uzenski
Page: 1 of 1

Question: Referring Exhibit A-12 Schedule B4.4, please answer the following questions:

e. Please identify the amount of pension expense DTE Electric has recovered from customers in its retail rates since December 31, 2002 and through the forecasted balance at April 30, 2021.

Answer: The analysis requested only exists for 2016 through April 30, 2021. Please see the attached file.

Attachments: *U-20561 ABDE-3.21e Pension Expense in Rates (2016-2021).xls*

DTE Electric Company
Prepaid Pension Asset ($000)

Case No.: U-20561
Discovery Request: ABDE-3.21e
Date Received: 10/4/2019
Witness: T. M. Uzenski

Estimated Annual Collections from Customers

	Annual Rates	2016	2017	2018	2019	2020	Jan-Apr 2021
U-17767 rates effective Dec. 2015 - Jan. 2017	101,567	101,567	8,464				
U-18014 rates effective Feb. 2017-Apr. 2018	79,271	-	72,665	26,424			
U-18255 rates effective May 2018-Apr. 2019	74,712	-	-	49,808	24,904		
U-20162 rates effective May 2019-Apr. 2020	42,991	-	-	-	28,661	14,330	
U-20561 rates effective May 2020-Apr. 2021	50,729					33,819	16,910
Estimated Pension Expense in Rates		101,567	81,129	76,232	53,565	48,150	16,910

Case History

Case Number and Effective Date	U-17767	eff. Dec. 2015
Pension Expense - Filed	95,269	Filed A-10 C5.9
Final Order Adjustments	6,298	Updated for Feb '15 Hewitt letter
Pension Expense - Final Order	101,567	Order p. 68
Case Number and Effective Date	U-18014	eff. Feb. 2017
Pension Expense - Filed	79,317	Filed A-10 C5.9
Final Order Adjustments	(46)	Order p. 86
Pension Expense - Final Order	79,271	
Case Number and Effective Date	U-18255	eff. May 2018
Pension Expense - Filed	88,209	Filed A-10 C5.9.1
Final Order Adjustments	(13,497)	ASU 715 Accting Proposal Filed A-10 C5.13
Pension Expense - Final Order	74,712	Order p. 6 (footnote 7)
Case Number and Effective Date	U-20162	eff. May 2019
Pension Expense - Filed	42,991	Filed A-13 C5.10
Final Order Adjustments	-	
Pension Expense - Final Order	42,991	Order p. 91 (adopted DTE Electric position)
Case Number and Effective Date	U-20561	eff. May 2020
Pension Expense - Filed	50,729	Filed A-13 C5.11
Final Order Adjustments	-	
Pension Expense - Final Order	50,729	Order pending

MPSC Staff's Answer to ABATE's 2nd Discovery Request
MPSC Case No. U-20561
December 4, 2019

Question:

Interrogatory No. 2.13. Please identify all 5-, 10-, 20-, and 50- year periods where the market experienced price appreciation or growth of 12.47% or higher.

Answer:

As noted on Revised Exhibit S-4, Schedule D-5, page 5 of 12, which notes the Ibbotson Classic Yearbook used in the CAPM analysis, the market experienced growth over 12.47% for the 5-year period from 1995 through 1999.

Respondent: Kirk Megginson

MPSC Staff's Answer to ABATE's 2nd Discovery Request
MPSC Case No. U-20561
December 4, 2019

Question:

Interrogatory No. 2.14. Please identify all 5-, 10-, 20-, and 50- year periods where the market experienced total returns of 14.77% or higher.

Response:

As noted on the Revised Exhibit S-4, Schedule D-5, page 5 of 12, which notes the Ibbotson Classic Yearbook used in the CAPM analysis, Staff noted one 5-year consecutive period, from 1995 through 1999, where total market returns exceeded 14.77%.

Respondent: Kirk Megginson

MPSC Staff's Answer to ABATE's 2nd Discovery Request
MPSC Case No. U-20561
December 4, 2019

Question:

Interrogatory No. 2.15. Please state whether Mr. Megginson is of the opinion that a market growth rate of 12.47% is sustainable in perpetuity. Please provide all supporting documents and analyses.

Response:

Mr. Megginson is not of the opinion that a 12.47% growth rate can be sustained in perpetuity. Mr. Megginson did not make such a claim in his pre-filed direct testimony. The 12.47% growth rate is a 4-year geometric annualized growth rate from Value Line's forecast of a 60% growth rate for the New York Stock Exchange for a 3-5-year period as indicated on Revised Exhibit No. S-4, Schedule D-5, page 7 of 12. Value Line does not indicate how it annualizes its 3-5-year market growth forecast.

Several studies suggest (noted below) that analysts' forecasts and estimates are important factors that influence investor behavior. Investors conclude that analyst's function as important "information intermediaries" that inform and influence investment decisions. Value Line is one of the largest financial information firms in the world whose analyst forecasts are widely viewed and regarded.

Womack, K. L. (1996). Do Brokerage Analysts' Recommendations Have Investment Value? *Journal of Finance* (Vol, LI, NO. 1)

Low, R. K., & Tan, E. (2016). The Role of Analyst Forecasts in the Momentum Effect. *The International Review of Financial Analysis*, Vol 48, 67-84. Retrieved from https://www.sciencedirect.com/science/article/pii/S1057521916301314

Respondent: Kirk Megginson

MPSC Staff's Answer to ABATE's 2nd Discovery Request
MPSC Case No. U-20561
December 4, 2019

Question:

Interrogatory No. 2.16. Please identify all analyses Mr. Megginson has undertaken to assess the reasonableness of a projected annual market growth rate of 12.47% or a total return on the market of 14.77%. Please provide all supporting documents and analyses. If Mr. Megginson has not performed any analyses to assess the reasonableness of his assumed growth rate of 12.47% or expected return on the market of 14.77%, do so state.

Response:

Mr. Megginson has not performed that analysis. Please refer to response 2.15.

Respondent: Kirk Megginson