



Otter Tail Corporation d/b/a
Otter Tail Power Company
Before the
North Dakota Public Service Commission

Application for Authority to
Increase Electric Rates in North Dakota
Case No. PU - 08 - ____
November 3, 2008

Volume 4A
Work Papers

Otter Tail Power Company

North Dakota General Rate Case Documents

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2007 Test Year work papers

Volume 4A – Section 1

2007 Test Year work papers

Jurisdictional Cost of Service Study
(JCOSS)

LINE NO	ITEM	ALLOC	REFERENCE	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	RATE BASE		Page 2-1 Line 32	459,913,760	187,173,203	272,740,557	1
2	TOTAL AVAILABLE FOR RETURN		Page 7-1 Line 43	28,964,255	12,942,144	16,022,111	2
3							3
4							4
5	RATE OF RETURN EARNED			6.30%	6.91%	5.87%	5
6							6
7	RATE OF RETURN REQUESTED		Page 17-1 Line 11		8.89%		7
8							8
9	OPERATING INCOME REQUIRED				16,639,698		9
10							10
11	TOTAL AVAILABLE FOR RETURN				12,942,144		11
12							12
13	OPERATING INCOME DEFICIENCY				3,697,554		13
14							14
15	INCREMENTAL TAXES	GRCF = 1.645413			2,386,449		15
16							16
17	REVENUE INCREASE REQUIRED				6,084,004		17
18							18
19	PERCENTAGE INCREASE				5.14%		19
20							20
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LINE NO	ITEM	ALLOC	REFERENCE	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	ELECTRIC PLANT IN SERVICE		Page 3-1 Line 52	978,261,122	409,987,820	568,273,302	1
2	ACCUMULATED DEPRECIATION		Page 4-12 Line 22	(454,347,840)	(189,745,784)	(284,602,057)	2
3							3
4							4
5	NET PLANT EXCLUDING BIG STONE PLANT CAPITALIZED ITEMS			529,913,282	220,242,036	303,671,245	5
6							6
7	NET CAPITALIZED ITEMS - BIG STONE PLANT			129,351	118,635	10,715	7
8	NET ELECTRIC PLANT IN SERVICE		Page 4-1 Line 28	524,042,632	220,360,672	303,681,961	8
9							9
10	PLANT HELD FOR FUTURE USE		Page 4-1 Line 47	29,656	12,871	16,785	10
11							11
12	CONSTRUCTION WORK IN PROGRESS		Page 5-1 Line 31	22,045,775	2,257,935	19,787,839	12
13							13
14	MATERIALS AND SUPPLIES		Page 5-1 Line 39	13,498,511	5,722,628	7,775,884	14
15							15
16	FUEL STOCKS		Page 5-1 Line 46	7,638,969	3,072,173	4,566,796	16
17							17
18	PREPAYMENTS		Page 5-1 Line 49	(31,526,342)	(13,256,872)	(18,269,470)	18
19							19
20	CUSTOMER ADVANCES		Page 5-1 Line 51	(129,099)	(54,286)	(74,812)	20
21							21
22	CASH WORKING CAPITAL		Page 5-1 Line 53	3,845,539	1,598,584	2,246,955	22
23							23
24	ACCUMULATED DEFERRED INCOME TAXES		Page 6-1 Line 16	(79,531,881)	(32,540,502)	(46,991,379)	24
25							25
26	UNAMORTIZED BALANCE - SPIRITWOOD		Page 6-1 Line 19	0	0	0	26
27							27
28	UNAMORTIZED RATE CASE EXPENSE		Page 6-1 Line 22	0	0	0	28
29							29
30							30
31							31
32	TOTAL AVERAGE RATE BASE			459,913,760	187,173,203	272,740,557	32
33							33
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OTTER TAIL POWER COMPANY
COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

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LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	PLANT IN SERVICE					1
2	PRODUCTION PLANT					2
3	AC 101 & 106 - BASE DEMAND	E1	265,318,040	105,413,237	159,904,803	3
4	PEAK DEMAND	D1	116,267,447	48,430,531	67,836,916	4
5	BASE ENERGY	E1	0	0	0	5
6						6
7	SUBTOTAL AC 101 & 106		381,585,487	153,843,768	227,741,719	7
8						8
9	AC 114 - BASE DEMAND	E1	1,101,931	437,807	664,124	9
10	PEAK DEMAND	D1	486,324	202,575	283,748	10
11	BASE ENERGY	E1	0	0	0	11
12						12
13	SUBTOTAL AC 114		1,588,255	640,382	947,872	13
14						14
15	TOTAL PRODUCTION PLANT	P10	383,173,741	154,484,150	228,689,591	15
16						16
17						17
18	TRANSMISSION PLANT					18
19	AC 101 & 106	D2	203,234,510	83,849,043	119,385,567	19
20	AC 114	D2	58,287	24,048	34,239	20
21						21
22	TOTAL TRANSMISSION PLANT		203,292,897	83,873,091	119,419,806	22
23						23
24						24
25	DISTRIBUTION PLANT					25
26	PRIMARY DEMAND	D3	100,970,644	44,470,444	56,500,200	26
27	SECONDARY DEMAND	D4	51,591,927	23,731,703	27,860,224	27
28	PRIMARY CUSTOMER	C2	58,148,137	25,643,355	32,504,781	28
29	SECONDARY CUSTOMER	C3	59,922,510	26,434,766	33,487,744	29
30	STREET LIGHTING	C4	11,989,203	5,041,497	6,947,706	30
31	AREA LIGHTING	C5	4,476,664	2,083,462	2,393,202	31
32	METERS	C6	19,597,938	8,612,975	10,984,962	32
33	LOAD MANAGEMENT	C9	9,069,489	3,998,084	5,071,405	33
34						34
35	TOTAL DISTRIBUTION PLANT	P60	315,766,511	140,016,287	175,750,224	35
36						36
37						37
38	GENERAL PLANT					38
39	PRODUCTION	P10	26,630,015	10,736,423	15,893,592	39
40	TRANSMISSION	D2	10,400,206	4,290,841	6,109,366	40
41	DISTRIBUTION	P60	17,440,568	7,733,447	9,707,121	41
42	CUSTOMER ACCOUNTS	OXC	12,839,882	5,554,087	7,285,775	42
43	CUSTOMER SERVICE & INFO	OXI	4,459,168	1,525,474	2,933,694	43
44	LOAD MANAGEMENT	C9	135,027	59,524	75,503	44
45						45
46	TOTAL GENERAL PLANT	P90	71,904,846	29,899,795	42,005,051	46
47						47
48						48
49	INTANGIBLE PLANT	P90	4,123,127	1,714,497	2,408,630	49
50						50
51		EPIS	978,261,122	409,987,820	568,273,302	51
52	TOTAL PLANT IN SERVICE					52
53						53
54						54
55						55
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OTTER TAIL POWER COMPANY
COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

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LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	ACCUMULATED DEPRECIATION					1
2	PRODUCTION PLANT					2
3	BASE DEMAND		(441,591,919)	(56,255,740)	(85,336,180)	3
4	PEAK DEMAND		(751,102,822)	(31,283,645)	(43,819,177)	4
5	BASE ENERGY		0	0	0	5
6						6
7	TOTAL PRODUCTION PLANT		(216,694,742)	(87,539,385)	(129,155,356)	7
8						8
9	TRANSMISSION PLANT		(76,356,247)	(31,502,500)	(44,853,747)	9
10						10
11						11
12	DISTRIBUTION PLANT		(131,655,231)	(58,378,187)	(73,277,043)	12
13						13
14						14
15	GENERAL PLANT		(28,483,355)	(11,844,076)	(16,639,279)	15
16						16
17						17
18	INTANGIBLE PLANT		(1,158,266)	(481,635)	(676,631)	18
19						19
20						20
21						21
22	TOTAL ACCUMULATED DEPRECIATION		(454,347,840)	(185,745,784)	(264,602,057)	22
23						23
24	NET PLANT EXCLUDING BSP CAPITALIZED ITEMS		523,913,282	220,242,036	303,671,245	24
25						25
26						26
27	BSP CAPITALIZED ITEMS		129,351	118,635	10,715	27
28						28
29						29
30	TOTAL NET PLANT IN SERVICE		524,042,632	220,360,672	303,681,961	30
31						31
32						32
33						33
34						34
35						35
36						36
37						37
38						38
39						39
40	PLANT HELD FOR FUTURE USE					40
41	PRODUCTION PLANT		0	0	0	41
42	TRANSMISSION PLANT		9,038	3,729	5,309	42
43	DISTRIBUTION PLANT		20,618	9,142	11,476	43
44	GENERAL PLANT		0	0	0	44
45	INTANGIBLE PLANT		0	0	0	45
46	TOTAL PLANT HELD FOR FUTURE USE		29,656	12,871	16,785	46
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OTTER TAIL POWER COMPANY
COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

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LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	CONST WORK-IN-PROGRESS - MAJOR PROJECTS					1
2	PRODUCTION PLANT	P10	0	0	0	2
3	TRANSMISSION PLANT	D2	0	0	0	3
4	DISTRIBUTION PLANT	P60	0	0	0	4
5	GENERAL PLANT	P90	0	0	0	5
6	INTANGIBLE PLANT	P90	0	0	0	6
7						7
8	TOTAL CMP - MAJOR PROJECTS		0	0	0	8
9						9
10	CONST WORK-IN-PROGRESS - SHORT TERM					10
11	PRODUCTION PLANT	P10	144,892	58,452	86,530	11
12	TRANSMISSION PLANT	D2	574,800	237,147	337,653	12
13	DISTRIBUTION PLANT	P60	3,202,396	1,419,997	1,782,399	13
14	GENERAL PLANT	P90	1,304,249	542,339	761,911	14
15	INTANGIBLE PLANT	P90	0	0	0	15
16						16
17	TOTAL CMP - SHORT TERM		5,226,428	2,257,935	2,968,492	17
18						18
19	CONST WORK-IN-PROGRESS - LONG TERM					19
20	PRODUCTION PLANT	P10	11,352,188	0	11,352,188	20
21	TRANSMISSION PLANT	D2	2,446,437	0	2,446,437	21
22	DISTRIBUTION PLANT	P60	2,479,891	0	2,479,891	22
23	GENERAL PLANT	P90	842,291	0	842,291	23
24	INTANGIBLE PLANT	P90	(301,460)	0	(301,460)	24
25						25
26	TOTAL CMP - LONG TERM		16,819,347	0	16,819,347	26
27						27
28	TOTAL CONSTRUCTION WORK-IN-PROGRESS		22,045,775	2,257,935	19,787,839	28
29						29
30	MATERIALS & SUPPLIES					30
31	PRODUCTION	P10	3,772,873	1,521,149	2,251,823	31
32	TRANSMISSION	D2	3,598,449	1,484,622	2,113,827	32
33	DISTRIBUTION	P60	6,127,090	2,716,857	3,410,233	33
34						34
35	TOTAL MATERIALS AND SUPPLIES		13,498,511	5,722,628	7,775,884	35
36						36
37	FUEL STOCKS					37
38	COAL STOCKS	E1	5,708,035	2,267,853	3,440,181	38
39	FUEL OIL STOCKS	D1	1,930,934	804,319	1,126,615	39
40						40
41	TOTAL FUEL STOCKS		7,638,969	3,072,173	4,566,796	41
42						42
43	PREPAYMENTS	NEPIS	(31,526,342)	(13,256,872)	(18,269,470)	43
44	CUSTOMER ADVANCES	NEPIS	(129,099)	(54,286)	(74,812)	44
45	CASH WORKING CAPITAL	OX	3,845,539	1,598,584	2,246,955	45
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47						47
48						48
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OTTER TAIL POWER COMPANY
COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

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LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	ACCUMULATED DEFERRED INCOME TAXES					1
2	ITEMS SO FLOWS THROUGH					2
3	FEDERAL		(4,449,065)	(2,064,775)	(2,384,290)	3
4	MINNESOTA		(671,579)	0	(671,579)	4
5	NORTH DAKOTA		(391,623)	(390,230)	(1,398)	5
6						6
7	SUBTOTAL		(5,512,272)	(2,455,005)	(3,057,267)	7
8	ALL OTHER					8
9	FEDERAL		(61,140,220)	(25,709,554)	(35,439,676)	9
10	MINNESOTA		(8,487,754)	0	(8,487,754)	10
11	NORTH DAKOTA		(4,391,025)	(4,375,944)	(15,601)	11
12						12
13	SUBTOTAL		(74,019,009)	(30,085,497)	(43,934,111)	13
14						14
15	TOTAL ACCUMULATED DEFERRED INCOME TAXES		(79,531,881)	(32,540,502)	(46,991,379)	15
16						16
17						17
18						18
19	UNAMORTIZED BALANCE - SPIRITWOOD PLANT	P10 DIRECTLY ASSIGNED TO JURISDICTION	0	0	0	19
20						20
21						21
22	UNAMORTIZED RATE CASE EXPENSES	R10 DIRECTLY ASSIGNED TO JURISDICTION	0	0	0	22
23						23
24						24
25						25
26						26
27	TOTAL AVERAGE RATE BASE		459,913,760	187,173,203	272,740,557	27
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OTTER TAIL POWER COMPANY
COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

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LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	OPERATING REVENUES					1
2	SALES OF ELECTRICITY		278,520,961	118,309,177	160,211,783	2
3	OTHER OPERATING REVENUE		34,277,583	13,804,432	20,473,151	3
4						4
5	TOTAL OPERATING REVENUE		312,798,544	132,113,609	180,684,935	5
6						6
7						7
8	OPERATING EXPENSES					8
9	PRODUCTION EXPENSES		185,407,210	67,714,739	97,692,471	9
10	TRANSMISSION EXPENSES		18,827,331	4,467,061	6,360,270	10
11	DISTRIBUTION EXPENSES		15,280,331	6,727,902	8,552,429	11
12	CUSTOMER ACCOUNTING EXPENSES		10,931,905	4,728,970	6,202,935	12
13	CUSTOMER SERVICE AND INFORMATION EXPENSES		6,387,900	2,185,290	4,202,610	13
14	SALES EXPENSES		1,194,443	701,476	482,966	14
15	ADMINISTRATIVE AND GENERAL EXPENSES		33,546,971	13,557,519	19,989,452	15
16	CHARITABLE CONTRIBUTIONS		226,783	114,816	111,967	16
17	DEPRECIATION EXPENSE		25,546,230	10,716,072	14,830,158	17
18	AMORTIZATION OF BIG STONE PLANT CAPITALIZED COSTS		0	0	0	18
19	SPIRITWOOD AMORTIZATION		0	0	0	19
20	GENERAL TAXES		9,411,607	3,957,594	5,454,013	20
21						21
22	TOTAL OPERATING EXPENSES		278,760,712	114,871,140	163,889,571	22
23						23
24						24
25	NET OPERATING INCOME BEFORE INCOME TAXES		34,037,832	17,242,469	16,795,363	25
26						26
27						27
28	INCOME TAX EXPENSE					28
29	INVESTMENT TAX CREDIT		(1,136,657)	(476,371)	(660,286)	29
30	DEFERRED INCOME TAXES		477,922	213,186	264,736	30
31	INCOME TAXES		7,989,374	4,563,511	3,425,863	31
32						32
33	TOTAL INCOME TAX EXPENSE		7,330,639	4,300,325	3,030,314	33
34						34
35						35
36						36
37	NET OPERATING INCOME		26,707,193	12,942,144	13,765,049	37
38						38
39	ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION					39
40						40
41			2,257,062	0	2,257,062	41
42						42
43	TOTAL AVAILABLE FOR RETURN		28,964,255	12,942,144	16,022,111	43
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OTTER TAIL POWER COMPANY
COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

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LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	OPERATING REVENUES					1
2						2
3	SALES OF ELECTRICITY	R10 DIRECTLY ASSIGNED TO JURISDICTION	278,520,961	118,309,177	160,211,783	3
4						4
5						5
6	OTHER OPERATING REVENUES					6
7	SALES FOR RESALE					7
8	MUNICIPALITIES & OFF SYSTEM SALES	DIRECTLY ASSIGNED TO FERC JURISDICTION	211,432	0	211,432	8
9	NON ASSOCIATED UTILITIES, COOPS & OPA					9
10	BUY SELL TRANSACTIONS	D2	0	0	0	10
11	ALL OTHER TRANSACTIONS					11
12	BASE DEMAND	E1	0	0	0	12
13	PEAK DEMAND	D1	0	0	0	13
14	BASE ENERGY		20,743,342	8,508,499	12,234,843	14
15	PEAK ENERGY	D1	0	0	0	15
16						16
17	TOTAL ALL OTHER TRANSACTIONS		20,743,342	8,508,499	12,234,843	17
18						18
19	TOTAL SALES FOR RESALE		20,954,774	8,508,499	12,446,275	19
20						20
21						21
22	OTHER ELECTRIC REVENUES					22
23	LATE FEES	C1 DIRECTLY ASSIGNED TO JURISDICTION	545,326	170,779	374,547	23
24	CONNECTION FEES	C1	315,745	89,754	225,991	24
25	RENT FROM ELECTRIC PROPERTY - BIG STONE	NEPS	644,002	270,804	373,198	25
26	RENT FROM ELECTRIC PROPERTY - COYOTE	NEPS	(20,857)	(8,686)	(11,971)	26
27	OTHER MISC ELECTRIC REVENUE	NEPS	11,846	4,981	6,865	27
28	ITA DEFICIENCY PAYMENTS	NEPS	3,170,821	1,333,335	1,837,486	28
29		NEPS	3,651,859	1,535,611	2,116,247	29
30	MISCELLANEOUS SERVICES	NEPS	0	0	0	30
31	WHEELING	NEPS	34,025	14,308	19,717	31
32	LOAD CONTROL AND DISPATCH	NEPS	433,023	0	433,023	32
33	RESIDENTIAL CONSERVATION SERVICES	NEPS	4,459,926	1,875,405	2,584,521	33
34		C1	76,895	9,642	67,252	34
35	TOTAL OTHER ELECTRIC REVENUES		13,322,809	5,295,933	8,026,876	35
36						36
37	TOTAL OTHER OPERATING REVENUES		34,277,583	13,804,432	20,473,151	37
38						38
39						39
40						40
41	TOTAL OPERATING REVENUES		312,798,544	132,113,609	180,684,935	41
42						42
43						43
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LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	OPERATING EXPENSES					1
2	PRODUCTION EXPENSES					2
3	PROD EXPENSES EXCLUDING PURCHASED POWER					3
4	BASE DEMAND	E1	11,909,550	4,731,771	7,177,779	4
5	PEAK DEMAND	D1	5,900,454	2,457,800	3,442,654	5
6	BASE ENERGY	E2	63,884,703	26,204,212	37,680,491	6
7	PEAK ENERGY	D1	6,236,150	2,597,632	3,638,518	7
8						8
9	TOTAL EXCLUDING PURCHASED POWER		87,930,958	35,991,415	51,939,443	9
10						10
11	PURCHASED POWER					11
12	BUY SELL TRANSACTIONS					12
13	ALL OTHER TRANSACTIONS	D2	0	0	0	13
14	BASE DEMAND	E1	4,343,702	1,725,792	2,617,910	14
15	PEAK DEMAND	D1	0	0	0	15
16	BASE ENERGY	E2	73,132,950	29,997,532	43,135,418	16
17	PEAK ENERGY	D1	0	0	0	17
18						18
19	TOTAL ALL OTHER TRANSACTIONS		77,476,352	31,723,324	45,753,028	19
20						20
21	TOTAL PURCHASED POWER		77,476,352	31,723,324	45,753,028	21
22						22
23	TOTAL PRODUCTION EXPENSES		165,407,210	67,714,739	97,692,471	23
24						24
25	TRANSMISSION EXPENSES					25
26						26
27		D2	10,827,331	4,467,061	6,360,270	27
28						28
29						29
30	DISTRIBUTION EXPENSES					30
31	PRIMARY DEMAND	D3	4,326,115	1,905,348	2,420,766	31
32	SECONDARY DEMAND	D4	1,385,723	637,417	748,306	32
33	PRIMARY CUSTOMER	C2	2,956,103	1,303,643	1,652,460	33
34	SECONDARY CUSTOMER	C3	2,391,285	1,054,914	1,336,372	34
35	STREET LIGHTING	C4	1,569,250	659,874	909,375	35
36	AREA LIGHTING	C5	44,713	20,809	23,903	36
37	METERS	C6	2,607,142	1,145,797	1,461,345	37
38	LOAD MANAGEMENT	C9	0	0	0	38
39						39
40	TOTAL DISTRIBUTION	OXD	15,280,331	6,727,802	8,552,529	40
41						41
42	CUSTOMER ACCOUNTING EXPENSES					42
43	METER READING	C7	4,843,083	2,044,032	2,799,052	43
44	OTHER	C8	6,088,822	2,684,738	3,404,083	44
45						45
46	TOTAL CUSTOMER ACCOUNTS	OXC	10,931,905	4,728,770	6,203,135	46
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OTTER TAIL POWER COMPANY
COST OF SERVICE STUDY
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LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	CUSTOMER SERVICE & INFORMATION EXPENSE					1
2	CONSERVATION & PROMOTIONAL REBATES	E2	3,692,028	1,000,000	2,692,028	2
3	OTHER	C1	2,695,872	1,185,290	1,510,582	3
4						4
5	TOTAL CUSTOMER SERV & INFORMATION EXP	Oxi	6,387,900	2,185,290	4,202,610	5
6						6
7	SALES EXPENSES					7
8	OFF-PEAK DEVELOPMENT					8
9	OTHER	C1	736,197	500,000	236,197	9
10		C1	458,245	201,476	256,769	10
11						11
12	TOTAL SALES EXPENSES		1,194,443	701,476	492,966	12
13						13
14	ADMINISTRATIVE & GENERAL EXPENSES					14
15	SALARIES, SUPPLIES, PENSIONS & BENEFITS					15
16	PRODUCTION					16
17	TRANSMISSION	OXPD	8,579,770	3,452,775	5,126,995	17
18	DISTRIBUTION	D2	3,290,947	1,357,755	1,933,192	18
19	CUSTOMER ACCOUNTS	OXD	5,814,175	2,559,933	3,254,242	19
20	CUSTOMER SERVICE & INFO	OXD	4,168,561	1,803,178	2,365,384	20
21		C1	1,435,880	631,311	804,569	21
22						22
23	TOTAL SALARIES, SUPPLIES, PENSIONS, AND BENEFITS		23,289,334	9,804,952	13,484,383	23
24	LOAD MANAGEMENT EXPENSES					24
25		C9	0	0	0	25
26	OUTSIDE SERVICES	NEPIS	1,727,010	726,210	1,000,800	26
27						27
28	PROPERTY INSURANCE	NEPIS	1,259,872	529,778	730,094	28
29						29
30	INJURIES & DAMAGES	NEPIS	1,646,497	692,354	954,143	30
31						31
32	REGULATORY COMMISSION EXPENSE	R10	1,918,795	263,370	1,655,425	32
33						33
34	GENERAL ADVERTISING	C1	1,379	606	772	34
35						35
36	MISCELLANEOUS, RENTS, MAINTENANCE	P90	3,704,085	1,540,249	2,163,836	36
37						37
38	TOTAL ADMINISTRATIVE & GENERAL EXP		33,546,971	13,557,519	19,989,452	38
39						39
40						40
41	CHARITABLE CONTRIBUTIONS	C1	226,783	114,816	111,967	41
42						42
43						43
44						44
45	TOTAL O & M EXPENSES		243,802,874	100,197,474	143,605,400	45
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NORTH DAKOTA

OTTER TAIL POWER COMPANY COST OF SERVICE STUDY TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES	RUN = TEST YEAR 10/24/08 08:28 AM	PAGE 11 - 1

LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	DEPRECIATION EXPENSE					1
2	PRODUCTION					2
3	BASE DEMAND	E1	7,286,535	2,895,006	4,391,529	3
4	PEAK DEMAND	D1	2,847,009	1,185,906	1,661,104	4
5	BASE ENERGY	E1	0	0	0	5
6						6
7	TOTAL PRODUCTION		10,133,545	4,080,911	6,052,633	7
8						8
9	TRANSMISSION	D2	3,912,664	1,614,258	2,298,406	9
10						10
11						11
12	DISTRIBUTION	P60	8,658,518	3,839,335	4,819,183	12
13						13
14						14
15	GENERAL	P90	2,275,461	946,193	1,329,268	15
16						16
17						17
18	INTANGIBLE	P90	566,043	235,374	330,668	18
19						19
20						20
21						21
22	TOTAL DEPRECIATION EXPENSE		25,546,230	10,716,072	14,830,158	22
23						23
24						24
25						25
26						26
27						27
28	BIG STONE EXPENSE OFFSETS	P10	0	0	0	28
29						29
30						30
31						31
32	SPIRITWOOD AMORTIZATION	P10	0	0	0	32
33						33
34						34
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OTTER TAIL POWER COMPANY
COST OF SERVICE STUDY
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LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	GENERAL TAXES		9,411,607	3,957,594	5,454,013	1
2	NET OPERATING INCOME BEFORE TAX (NOBT)		34,037,632	17,242,469	16,795,363	2
3						3
4						4
5	INVESTMENT TAX CREDIT		(1,136,657)	(476,371)	(660,286)	5
6	AMORTIZE PRIOR YEARS CREDIT		0	0	0	6
7	DEBITS UTILIZED					7
8						8
9	TOTAL INVESTMENT TAX CREDIT		(1,136,657)	(476,371)	(660,286)	9
10						10
11	DEFERRED INCOME TAXES					11
12	ITEMS SOUTH DAKOTA FLOWS THROUGH					12
13	FEDERAL		587,347	272,583	314,764	13
14	MINNESOTA		68,662	0	68,662	14
15	NORTH DAKOTA		53,223	53,033	190	15
16						16
17	SUB TOTAL		709,232	325,616	383,616	17
18						18
19	ALL OTHER					19
20	FEDERAL		(250,385)	(109,492)	(150,893)	20
21	MINNESOTA		32,023	0	32,023	21
22	NORTH DAKOTA		(2,948)	(2,938)	(11)	22
23						23
24	SUB TOTAL		(231,310)	(112,430)	(118,880)	24
25						25
26	TOTAL DEFERRED INCOME TAXES		477,922	213,186	264,736	26
27						27
28						28
29	CURRENT INCOME TAXES					29
30	FEDERAL INCOME TAXES		6,736,382	3,808,410	2,927,972	30
31	MINNESOTA INCOME TAXES		488,239	0	488,239	31
32	NORTH DAKOTA INCOME TAXES		754,753	755,101	(348)	32
33						33
34	TOTAL CURRENT INCOME TAXES		7,989,374	4,563,511	3,425,863	34
35						35
36	TOTAL INCOME TAXES		7,330,039	4,300,325	3,030,314	36
37						37
38						38
39	NET OPERATING INCOME		26,707,193	12,942,144	13,765,049	39
40						40
41	AFDC		2,257,062	0	2,257,062	41
42						42
43	TOTAL AVAILABLE FOR RETURN		28,964,255	12,942,144	16,022,111	43
44						44
45						45
46	RATE OF RETURN ON RATE BASE		6.30%	6.91%	5.87%	46
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LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	DEVELOPMENT OF FEDERAL INCOME TAX EXPENSE					1
2	NET OPERATING INCOME BEFORE TAX (NOBT)		34,037,832	17,242,469	16,795,363	2
3	LESS: INTEREST COST		12,265,525	5,091,111	7,174,414	3
4						4
5	NET INCOME BEFORE TAX					5
6			21,772,307	12,151,358	9,620,949	6
7	FEDERAL SCHEDULE M ADJUSTMENTS:					7
8	ADDITIONAL TAX DEPRECIATION	NEPIS	2,701,294	1,135,898	1,565,396	8
9	COST TO REMOVE	NEPIS	3,949,203	1,660,645	2,288,558	9
10	DIRECTLY ASSIGNED SCHEDULE M ITEMS	NEPIS	(83,287)	(59,233)	(24,054)	10
11	ACCURED VACATION PAY	NEPIS	87,932	36,676	50,256	11
12	CHARGES - OPERATING RESERVES	NEPIS	4,671,607	1,964,501	2,707,106	12
13	PROVISIONS - OPERATING RESERVES	NEPIS	(6,598,414)	(3,615,646)	(4,982,769)	13
14	UNBILLED REVENUES	NEPIS	0	0	0	14
15	PREFERRED DIVIDENDS PAID CREDIT	NEPIS	160,775	67,606	93,169	15
16	OTHER SCHEDULE M ITEMS	NEPIS	(1,606,800)	(675,662)	(931,138)	16
17						17
18	SUBTOTAL FEDERAL SCHEDULE M ADJUSTMENTS		12,722,510	515,086	757,424	18
19						19
20	FEDERAL ADJUSTED INCOME BEFORE INCOME TAXES		20,499,797	11,636,272	8,863,525	20
21						21
22	LESS:					22
23	MINNESOTA STATE INCOME TAXES		498,239	0	498,239	23
24	NORTH DAKOTA STATE INCOME TAXES		754,753	755,101	(348)	24
25						25
26	FEDERAL TAXABLE INCOME		19,246,804	10,881,171	8,365,634	26
27	FEDERAL TAX RATE		35.00%	35.00%	35.00%	27
28						28
29	FEDERAL INCOME TAX BEFORE CREDITS		6,736,382	3,808,410	2,927,972	29
30	INVESTMENT TAX CREDIT - DEBITS UTILIZED		0	0	0	30
31						31
32	FEDERAL INCOME TAXES		6,736,382	3,808,410	2,927,972	32
33						33
34						34
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OTTER TAIL POWER COMPANY
COST OF SERVICE STUDY
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LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	DEVELOPMENT OF MINNESOTA STATE INCOME TAX EXPENSE					1
2	FEDERAL ADJUSTED INCOME BEFORE INCOME TAXES		6,951,228	0	6,951,228	2
3						3
4	MINNESOTA ADJUSTMENTS TO FEDERAL SCHEDULE M:					4
5	PAY/SOP ADJUSTMENT		0	0	0	5
6	CHANGE IN EXCESS TAX DEPRECIATION - MN		(2,401,942)	0	(2,401,942)	6
7	CHANGE IN ACRS - ORDINARY LOSS		0	0	0	7
8	PREFERRED DIVIDENDS PAID CREDIT		78,068	0	78,068	8
9	MISCELLANEOUS ADJUSTMENTS TO FED SCHEDULE M		456,721	0	456,721	9
10						10
11	TOTAL MINNESOTA ADJUSTMENTS TO FED SCHEDULE M		(1,867,153)	0	(1,867,153)	11
12	MINNESOTA TAXABLE INCOME		5,084,075	0	5,084,075	12
13	MINNESOTA TAX RATE		9.80%	0.00%	9.80%	13
14	MINNESOTA INCOME TAX		498,239	0	498,239	14
15						15
16						16
17						17
18						18
19						19
20						20
21						21
22						22
23						23
24						24
25	DEVELOPMENT OF NORTH DAKOTA STATE INCOME TAX EXPENSE					25
26	FEDERAL ADJUSTED INCOME BEFORE INCOME TAXES		11,617,354	11,636,272	(18,917)	26
27						27
28	NORTH DAKOTA ADJUSTMENTS TO FEDERAL SCHEDULE M:					28
29	CHANGE IN EXCESS TAX DEPRECIATION - ND		(7,859)	(7,783)	(76)	29
30	CHANGE IN ACRS - ORDINARY LOSS - ND		0	0	0	30
31	CHANGE IN INCOME FROM ADR PROPERTY - ND		0	0	0	31
32	MISCELLANEOUS ADJUSTMENTS TO FED SCHEDULE M		(3,821)	(3,785)	(37)	32
33						33
34	TOTAL NORTH DAKOTA ADJUSTMENTS TO FED SCHEDULE M		(11,680)	(11,567)	(113)	34
35	SUBTOTAL		11,605,675	11,624,704	(19,030)	35
36	DEDUCTION OF FEDERAL INCOME TAXES		(5,912)	0	(5,912)	36
37						37
38	NORTH DAKOTA TAXABLE INCOME		11,611,587	11,624,704	(13,118)	38
39	NORTH DAKOTA TAX RATE		6.50%	6.50%	6.50%	39
40						40
41						41
42	NORTH DAKOTA INCOME TAX		754,753	755,101	(348)	42
43						43
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NORTH DAKOTA

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LINE NO	ITEM	ALLOCATION FACTOR	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	MWH CONSUMPTION AT GENERATORS - PARTIAL PERCENTAGE	E1	4,082,438	1,621,989	2,460,449	1
2			100.000000%	39.730897%	60.269103%	2
3						3
4	MWH CONSUMPTION AT GENERATORS - TOTAL PERCENTAGE	E2	4,595,203	1,884,859	2,710,344	4
5			100.000000%	41.017975%	58.982025%	5
6						6
7	GENERATION DEMAND FACTOR PERCENTAGE	D1	622,216	259,222	363,094	7
8			100.000000%	41.654420%	58.345580%	8
9						9
10	TRANSMISSION DEMAND FACTOR PERCENTAGE	D2	628,307	259,222	369,085	10
11			100.000000%	41.257266%	58.742734%	11
12						12
13	DISTRIBUTION - PRIMARY DEMAND FACTOR PERCENTAGE	D3	761,059	335,193	425,866	13
14			100.000000%	44.042944%	55.957056%	14
15						15
16	DISTRIBUTION - SECONDARY DEMAND FACTOR PERCENTAGE	D4	999,305	459,669	539,636	16
17			100.000000%	45.998869%	54.001131%	17
18						18
19	CUSTOMER OR METER FACTORS TOTAL RETAIL CUSTOMERS PERCENTAGE	C1	129,675	57,014	72,661	19
20			100.000000%	43.966840%	56.033160%	20
21						21
22	RETAIL SERVICE LOCATIONS PERCENTAGE	C2	135,857	59,913	75,944	22
23			100.000000%	44.100046%	55.899954%	23
24						24
25	SECONDARY SERVICE LOCATIONS PERCENTAGE	C3	135,784	59,901	75,883	25
26			100.000000%	44.114918%	55.885082%	26
27						27
28	STREET LIGHTING FACTOR PERCENTAGE	C4	4,185,546	1,760,035	2,425,511	28
29			100.000000%	42.050308%	57.949692%	29
30						30
31	AREA LIGHTING FACTOR PERCENTAGE	C5	3,688,552	1,716,671	1,971,881	31
32			100.000000%	46.540512%	53.459488%	32
33						33
34	METER FACTOR PERCENTAGE	C6	29,240,646	12,850,789	16,389,857	34
35			100.000000%	43.948376%	56.051624%	35
36						36
37	METER READING FACTOR PERCENTAGE	C7	173,474	73,215	100,259	37
38			100.000000%	42.205172%	57.794828%	38
39						39
40	SYSTEM SERVICE LOCATIONS PERCENTAGE	C8	135,879	59,913	75,966	40
41			100.000000%	44.092906%	55.907094%	41
42						42
43	LOAD MANAGEMENT FACTOR PERCENTAGE	C9	40,923	18,040	22,883	43
44			100.000000%	44.082790%	55.917210%	44
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NORTH DAKOTA

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LINE NO	ITEM	ALLOCATION FACTOR	TOTAL COMPANY	NORTH DAKOTA	OTHER	LINE NO
0						1
1	GROSS PLANT IN SERVICE					2
2	PRODUCTION PLANT	P10	383,173,741	154,484,150	226,689,591	3
3	PERCENTAGE		100.000000%	40.316988%	59.683002%	4
4						5
5	DISTRIBUTION PLANT	P60	315,766,511	140,016,287	175,750,224	6
6	PERCENTAGE		100.000000%	44.341715%	55.658285%	7
7						8
8	GENERAL PLANT	P90	71,904,846	29,899,795	42,005,051	9
9	PERCENTAGE		100.000000%	41.592448%	58.417552%	10
10						11
11	ELECTRIC PLANT IN SERVICE	EPIS	978,261,122	409,987,820	568,273,302	12
12	PERCENTAGE		100.000000%	41.909855%	58.090145%	13
13						14
14	NET ELECTRIC PLANT IN SERVICE	NEPIS	524,042,632	220,360,672	303,681,961	15
15	PERCENTAGE		100.000000%	42.050142%	57.949858%	16
16						17
17	OPERATION AND MAINTENANCE EXPENSE					18
18	PRODUCTION EXPENSE (EXCL ENERGY)	OPPD	22,153,706	8,915,363	13,238,343	19
19	PERCENTAGE		100.000000%	40.243211%	59.756789%	20
20						21
21	DISTRIBUTION EXPENSE	OXD	15,280,331	6,727,802	8,552,529	22
22	PERCENTAGE		100.000000%	44.029165%	55.970835%	23
23						24
24	CUSTOMER ACCOUNTS EXPENSE	OXC	10,931,905	4,728,770	6,203,135	25
25	PERCENTAGE		100.000000%	43.256597%	56.743403%	26
26						27
27	CUSTOMER SERVICE & INFORMATION EXPENSE	OXI	6,387,800	2,185,290	4,202,510	28
28	PERCENTAGE		100.000000%	34.209830%	65.790170%	29
29						30
30	OTHER DEFERRED INCOME TAX FACTOR					31
31	MINNESOTA	NPISM	253,639,255	0	253,639,255	32
32	PERCENTAGE		100.000000%	0.000000%	100.000000%	33
33						34
34	NORTH DAKOTA	NPISN	221,150,321	220,360,672	789,649	35
35	PERCENTAGE		100.000000%	99.642936%	0.357064%	36
36						37
37	EXCLUDING SOUTH DAKOTA	NPMNR	474,821,241	220,360,672	254,460,569	38
38	PERCENTAGE		100.000000%	46.409186%	53.590814%	39
39						40
40	LONG-TERM CWP RATIO (W/AFDC)	CWPLT	16,819,347	0	16,819,347	41
41	PERCENTAGE		100.000000%	0.000000%	100.000000%	42
42						43
43	REVENUE	R10	278,520,961	118,309,177	160,211,783	44
44	PERCENTAGE		100.000000%	42.477657%	57.522343%	45
45						46
46	LABOR AND RELATED EXPENSE	LRE	98,128,145	40,581,805	58,546,340	47
47	PERCENTAGE		100.000000%	40.938732%	59.061268%	48
48						49
49	TOTAL O & M EXPENSE	OX				50
50	PERCENTAGE					51
51						52
52						53
53						54
54						55
55						56
56						57
57						58
58						59
59						60

LINE NO	ITEM	AMOUNT	AMOUNT AS A PERCENT OF TOTAL	COST OF CAPITAL	RATE OF RETURN	LINE NO
1	CAPITAL STRUCTURE - RATE OF RETURN					1
2						2
3						3
4	LONG-TERM DEBT	185,725,713	43.106%	6.30%	2.72%	4
5	PREFERRED STOCK	15,500,000	3.597%	4.75%	0.17%	5
6	COMMON EQUITY	228,633,133	53.297%	11.25%	6.00%	6
7						7
8						8
9						9
10						10
11	TOTAL	\$430,858,846	100.00%		8.89%	11
12						12
13						13
14						14
15						15
16						16
17						17
18						18
19						19
20						20
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60						60

LINE NO	ITEM	ALLOCATION	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	CASH WORKING CAPITAL CALCULATION - REVENUE LEAD DAYS					1
2	REVENUES					2
3	COMPUTER MAINTAINED BILLINGS		256,380,509	108,807,866	147,572,643	3
4	MANUALLY MAINTAINED BILLINGS		23,001,523	9,761,844	13,239,678	4
5	COST OF ENERGY REVENUES	R10	0	0	0	5
6	SALES FOR RESALE		20,954,774	8,508,489	12,446,275	6
7	RENT FROM ELECTRIC PROPERTY		644,002	270,804	373,198	7
8	MISCELLANEOUS		3,170,821	1,333,335	1,837,486	8
9	ITA DEFICIENCY PAYMENTS		3,651,858	1,535,611	2,116,247	9
10	WHEELING		433,023	0	433,023	10
11	LOAD CONTROL AND DISPATCH		4,459,926	1,875,405	2,584,521	11
12	RENT FROM ELECTRIC PROPERTY - BIG STONE		(20,657)	(8,686)	(11,971)	12
13	RENT FROM ELECTRIC PROPERTY - COYOTE		11,846	4,981	6,865	13
14	PROFIT ON MATERIALS AND SUPPLIES		0	0	0	14
15	RUBBER GOODS TESTING		34,025	14,308	19,717	15
16	RESIDENTIAL CONSERVATION SERVICES		76,895	9,642	67,252	16
17						17
18						18
19	TOTAL REVENUES		312,798,544	132,113,609	180,684,935	19
20						20
21	REVENUE LEAD DAYS FROM SERVICE TO COLLECTION					21
22	COMPUTER MAINTAINED BILLINGS		N/A	38.1	N/A	22
23	MANUALLY MAINTAINED BILLINGS		N/A	43.1	N/A	23
24	COST OF ENERGY REVENUES		N/A	127.8	N/A	24
25	SALES FOR RESALE		N/A	25.4	N/A	25
26	RENT FROM ELECTRIC PROPERTY		N/A	-98.4	N/A	26
27	MISCELLANEOUS		N/A	39.0	N/A	27
28	ITA DEFICIENCY PAYMENTS		N/A	53.2	N/A	28
29	WHEELING		N/A	37.8	N/A	29
30	LOAD CONTROL AND DISPATCH		N/A	33.6	N/A	30
31	RENT FROM ELECTRIC PROPERTY - BIG STONE		N/A	37.5	N/A	31
32	RENT FROM ELECTRIC PROPERTY - COYOTE		N/A	37.5	N/A	32
33	PROFIT ON MATERIALS AND SUPPLIES		N/A	37.5	N/A	33
34	RUBBER GOODS TESTING		N/A	37.5	N/A	34
35	RESIDENTIAL CONSERVATION SERVICES		N/A	37.5	N/A	35
36						36
37						37
38						38
39	REVENUE DOLLAR DAYS (REVENUES X REVENUE LEAD DAYS)		9,768,097,403	4,146,579,712	5,622,517,692	39
40	COMPUTER MAINTAINED BILLINGS		991,385,628	420,735,489	570,650,139	40
41	MANUALLY MAINTAINED BILLINGS		0	0	0	41
42	COST OF ENERGY REVENUES		532,251,260	216,115,872	316,135,388	42
43	SALES FOR RESALE		(55,641,744)	(23,397,433)	(32,244,312)	43
44	RENT FROM ELECTRIC PROPERTY		110,978,726	46,666,712	64,312,014	44
45	MISCELLANEOUS		194,278,846	81,694,531	112,584,315	45
46	ITA DEFICIENCY PAYMENTS		16,368,267	0	16,368,267	46
47	WHEELING		149,853,514	63,013,615	86,839,898	47
48	LOAD CONTROL AND DISPATCH		(773,099)	(325,731)	(447,368)	48
49	RENT FROM ELECTRIC PROPERTY - BIG STONE		443,338	186,792	256,545	49
50	RENT FROM ELECTRIC PROPERTY - COYOTE		0	0	0	50
51	PROFIT ON MATERIALS AND SUPPLIES		1,273,423	536,534	736,889	51
52	RUBBER GOODS TESTING		2,876,820	381,582	2,515,238	52
53	RESIDENTIAL CONSERVATION SERVICES					53
54	TOTAL DOLLAR DAYS		11,711,372,380	4,951,167,674	6,760,204,706	54
55						55
56						56
57	AVG REVENUE LEAD DAYS (TOTAL REV DOLLAR DAYS / TOTAL REV)		37.4	37.5	37.4	57
58						58
59						59
60						60

OTTER TAIL POWER COMPANY COST OF SERVICE STUDY TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES										RUN = TEST YEAR 10/24/08 08:28 AM		PAGE 19 - 1	
LINE NO	ITEM	OPERATING EXPENSE	EXPENSE PER DAY AT 365 DAYS PER YEAR	EXPENSE LAG DAYS	EXCESS REVENUE LEAD DAYS OF OVER EXPENSE LAG DAYS	NET REVENUE LAG DOLLARS	LINE NO						
1							1						
2							2						
3	E2	26,328,397	72,133	16.0	21.4	1,543,638	3						
4							4						
5	E1	3,735,087	10,233	8.9	28.5	291,644	5						
6							6						
7		38,447,453	105,335	32.8	4.6	484,543	7						
8							8						
9	LRE	29,883,940	81,901	13.9	23.5	1,924,678	9						
10							10						
11		22,399,352	61,368	19.4	18.0	1,104,626	11						
12							12						
13		4,168,544	11,421	316.5	-279.1	(3,187,581)	13						
14							14						
15		362,965	984	316.5	-279.1	(277,550)	15						
16							16						
17		2,288,010	6,214	43.9	-6.5	(40,389)	17						
18							18						
19		502,887	1,378	20.7	16.7	23,009	19						
20							20						
21		0	0	43.9	-6.5	0	21						
22							22						
23		0	0	20.7	16.7	0	23						
24							24						
25	NEPIS					4,526	25						
26							26						
27	NEPIS					379,929	27						
28							28						
29	NEPIS					10,919	29						
30							30						
31		(1,989,429)	(5,450)	0.0		0	31						
32							32						
33		(3,393,243)	(9,297)	0.0		0	33						
34							34						
35	R10	(1,635,219)	(4,480)	1.9		(8,312)	35						
36							36						
37	R10	0	0	61.1		0	37						
38							38						
39	R10	(5,813,859)	(15,928)	15.5		(246,890)	39						
40							40						
41	R10	(722,428)	(1,979)	35.2		(69,670)	41						
42							42						
43							43						
44						1,936,920	44						
45							45						
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OTTER TAIL POWER COMPANY COST OF SERVICE STUDY TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES			RUN = TEST YEAR 1/02/08 08:28 AM			PAGE 20 -1	
LINE NO	ITEM	OPERATING EXPENSE	EXPENSE PER DAY AT 365 DAYS PER YEAR	EXPENSE LAG DAYS	EXCESS REVENUE OVER LEAD DAYS OF EXPENSE LAG DAYS	NET REVENUE LAG DOLLARS	LINE NO
1	CASH WORKING CAPITAL CALCULATION BY THE APPLICATION OF						1
2	LEAD-LAG FACTORS-NORTH DAKOTA JURISDICTION						2
3	FUEL - COAL	21,792,898	59,707	16.0	21.5	1,283,691	3
4							4
5	FUEL - OIL	2,920,848	8,002	8.9	28.6	228,866	5
6							6
7	PURCHASED POWER	31,723,324	86,913	32.8	4.7	408,492	7
8							8
9	LABOR AND ASSOCIATED PAYROLL EXPENSE						9
10							10
11	ALL OTHER O&M EXPENSE	24,600,235	67,398	13.9	23.6	1,590,591	11
12							12
13	PROPERTY TAXES (EXCL COAL CONVERSION TAXES)	19,160,169	52,484	19.4	18.1	950,134	13
14							14
15	COAL CONVERSION TAXES	3,640,599	9,974	316.5	-279.0	(2,782,877)	15
16							16
17	FEDERAL INCOME TAXES	316,995	868	316.5	-279.0	(242,312)	17
18							18
19	STATE INCOME TAXES	3,808,410	10,434	43.9	-6.4	(66,778)	19
20							20
21	INCREMENTAL FEDERAL INCOME TAXES	755,101	2,069	73.0	-35.5	(73,441)	21
22							22
23	INCREMENTAL STATE INCOME TAXES	0	0	43.9	-6.4	0	23
24							24
25	BANK BALANCES	0	0	73.0	-35.5	0	25
26							26
27	SPECIAL DEPOSITS					3,953	27
28							28
29	WORKING FUNDS					331,811	29
30						9,537	30
31	TAX COLLECTIONS AVAIL - FICA WITHHOLDING	(1,637,135)	(4,485)	0.0	0	0	31
32							32
33	TAX COLLECTIONS AVAIL - FEDERAL WITHHOLDING	(2,792,358)	(7,650)	0.0	0	0	33
34							34
35	TAX COLLECTIONS AVAIL - STATE WITHHOLDING- MN	0	0	1.9	0	0	35
36							36
37	TAX COLLECTIONS AVAIL - STATE WITHHOLDING- ND	(256,507)	(703)	61.1	(42,939)	(42,939)	37
38							38
39	TAX COLLECTIONS AVAILABLE - STATE SALES TAX	(2,020)	(6)	26.1	(144)	(144)	39
40							40
41	TAX COLLECTIONS AVAILABLE - FRANCHISE TAXES	0	0	0.0	0	0	41
42							42
43	TOTAL CASH WORKING CAPITAL REQUIREMENT - NORTH DAKOTA					1,598,584	43
44							44
45							45
46							46
47							47
48							48
49							49
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OTTER TAIL POWER COMPANY COST OF SERVICE STUDY TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES			RUN = TEST YEAR 10/24/08 08:28 AM			PAGE 21 -1	
LINE NO	ITEM	OPERATING EXPENSE	EXPENSE PER DAY AT 365 DAYS PER YEAR	EXPENSE LAG DAYS	EXCESS REVENUE LEAD DAYS OF OVER EXPENSE LAG DAYS	NET REVENUE LAG DOLLARS	LINE NO
1	CASH WORKING CAPITAL CALCULATION BY THE APPLICATION OF						1
2	LEAD-LAG FACTORS: SOUTH DAKOTA JURISDICTION						2
3	FUEL - COAL	4,965,336	13,604	16.0	21.4	291,118	3
4	FUEL - OIL	688,871	1,887	8.9	28.5	53,789	4
5							5
6	PURCHASED POWER	7,241,717	19,840	32.8	4.6	91,265	6
7							7
8	LABOR AND ASSOCIATED PAYROLL EXPENSE	5,313,149	14,557	13.9	23.5	342,079	8
9	ALL OTHER O&M EXPENSE	4,005,092	10,973	19.4	18.0	197,511	9
10	PROPERTY TAXES (EXCL COAL CONVERSION TAXES)	813,191	2,228	316.5	-279.1	(821,827)	10
11	COAL CONVERSION TAXES	70,806	194	316.5	-279.1	(64,144)	11
12	FEDERAL INCOME TAXES	676,191	1,853	43.9	-6.5	(12,042)	12
13	STATE INCOME TAXES	0	0	0.0	37.4	0	13
14	INCREMENTAL FEDERAL INCOME TAXES	0	0	43.9	-6.5	0	14
15	INCREMENTAL STATE INCOME TAXES	0	0	0.0	37.4	0	15
16	BANK BALANCES						16
17	SPECIAL DEPOSITS						17
18	WORKING FUNDS						18
19	TAX COLLECTIONS AVAIL - FICA WITHHOLDING	(353,589)	(969)	0.0		883	19
20	TAX COLLECTIONS AVAIL - FEDERAL WITHHOLDING	(603,092)	(1,652)	0.0		74,116	20
21	TAX COLLECTIONS AVAIL - STATE WITHHOLDING- MN	0	0	1.9		2,130	21
22	TAX COLLECTIONS AVAIL - STATE WITHHOLDING- ND	0	0	61.1		0	22
23	TAX COLLECTIONS AVAILABLE - STATE SALES TAX	(1,212,766)	(3,323)	16.3		(54,159)	23
24	TAX COLLECTIONS AVAILABLE - FRANCHISE TAXES	0	0	0.0		0	24
25	TOTAL CASH WORKING CAPITAL REQUIREMENT - SOUTH DAKOTA					310,720	25
26							26
27							27
28							28
29							29
30							30
31							31
32							32
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OTTER TAIL POWER COMPANY COST OF SERVICE STUDY TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES			RUN = TEST YEAR 10/24/08 08:28 AM			PAGE 22 - 1	
LINE NO	ITEM	OPERATING EXPENSE	EXPENSE PER DAY AT 365 DAYS PER YEAR	EXPENSE LAG DAYS	EXCESS REVENUE LEAD DAYS OF OVER EXPENSE LAG DAYS	NET REVENUE LAG DOLLARS	LINE NO
1	CASH WORKING CAPITAL CALCULATION BY THE APPLICATION OF						1
2	LEAD-LAG FACTORS-FERC JURISDICTION						2
3	FUEL - COAL	43,485	119	16.0	17.5	2,085	3
4	FUEL - OIL	6,773	19	8.9	24.6	456	4
5		63,858	175	32.8	0.7	122	5
6	PURCHASED POWER	283,045	775	13.9	19.6	15,199	6
7	LABOR AND ASSOCIATED PAYROLL EXPENSE	189,846	520	19.4	14.1	7,334	7
8	ALL OTHER O&M EXPENSE	35,422	97	316.5	-283.0	(27,465)	8
9	PROPERTY TAXES (EXCL COAL CONVERSION TAXES)	3,084	8	316.5	-283.0	(2,391)	9
10	COAL CONVERSION TAXES	(16,052)	(44)	43.9	-10.4	457	10
11	FEDERAL INCOME TAXES	(5,500)	(19)	43.9	-10.4	157	11
12	STATE INCOME TAXES	0	0	43.9	-10.4	0	12
13	INCREMENTAL FEDERAL INCOME TAXES	0	0	43.9	-10.4	0	13
14	INCREMENTAL STATE INCOME TAXES	0	0	43.9	-10.4	0	14
15	BANK BALANCES						15
16	NEPIS						16
17	SPECIAL DEPOSITS						17
18	NEPIS						18
19	WORKING FUNDS						19
20	NEPIS						20
21	TAX COLLECTIONS AVAIL - FICA WITHHOLDING	(18,837)	(52)	0.0		93	21
22	LRE						22
23	TAX COLLECTIONS AVAIL - FEDERAL WITHHOLDING	(32,128)	(88)	0.0		0	23
24	LRE						24
25	TAX COLLECTIONS AVAIL - STATE WITHHOLDING- MN	0	0	1.9		0	25
26	LRE						26
27	TAX COLLECTIONS AVAIL - STATE WITHHOLDING- ND	0	0	61.1		0	27
28	LRE						28
29	TAX COLLECTIONS AVAILABLE - STATE SALES TAX	0	0	0.0		0	29
30	LRE						30
31	TAX COLLECTIONS AVAILABLE - FRANCHISE TAXES	0	0	0.0		0	31
32	LRE						32
33							33
34							34
35							35
36							36
37							37
38							38
39							39
40							40
41							41
42							42
43	TOTAL CASH WORKING CAPITAL REQUIREMENT - FERC					(885)	43
44							44
45							45
46							46
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OTTER TAIL POWER COMPANY COST OF SERVICE STUDY TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES			RUN = TEST YEAR 10/24/08 08:28 AM		PAGE 23 - 1		
LINE NO	ITEM	OPERATING EXPENSE	EXPENSE PER DAY AT 365 DAYS PER YEAR	EXPENSE LAG DAYS	EXCESS REVENUE LEAD DAYS OF OVER EXPENSE LAG DAYS	NET REVENUE LAG DOLLARS	LINE NO
1	CASH WORKING CAPITAL CALCULATION BY THE APPLICATION OF LEAD-LAG FACTORS - TOTAL CO.						1
2	FUEL - COAL	E2				3,120,532	2
3	FUEL - OIL	E1				574,755	3
4							4
5							5
6	PURCHASED POWER					984,423	6
7							7
8	LABOR AND ASSOCIATED PAYROLL EXPENSE	LRE				3,872,547	8
9							9
10	ALL OTHER O&M EXPENSE					2,259,605	10
11							11
12	PROPERTY TAXES (EXCL COAL CONVERSION TAXES)					(6,619,750)	12
13							13
14	COAL CONVERSION TAXES					(576,397)	14
15							15
16	FEDERAL INCOME TAXES					(1,187,511)	16
17							17
18	STATE INCOME TAXES					(50,276)	18
19							19
20	INCREMENTAL FEDERAL INCOME TAXES					0	20
21							21
22	INCREMENTAL STATE INCOME TAXES					0	22
23							23
24	BANK BALANCES	NEPIS				9,400	24
25							25
26	SPECIAL DEPOSITS	NEPIS				789,085	26
27							27
28	WORKING FUNDS	NEPIS				22,679	28
29							29
30	TAX COLLECTIONS AVAIL - FICA WITHHOLDING	LRE				0	30
31							31
32	TAX COLLECTIONS AVAIL - FEDERAL WITHHOLDING	LRE				0	32
33							33
34	TAX COLLECTIONS AVAIL - STATE WITHHOLDING- MN	R10				(8,512)	34
35							35
36	TAX COLLECTIONS AVAIL - STATE WITHHOLDING- ND	R10				(42,939)	36
37							37
38	TAX COLLECTIONS AVAILABLE - STATE SALES TAX	R10				(301,193)	38
39							39
40	TAX COLLECTIONS AVAILABLE - FRANCHISE TAXES	R10				(69,670)	40
41							41
42							42
43							43
44	TOTAL CASH WORKING CAPITAL REQUIREMENT - TOTAL COMPANY					3,845,539	44
45							45
46							46
47							47
48							48
49							49
50							50
51							51
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2007 Test Year work papers

Class Cost of Service Study
(CCOSS)

LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	RATE BASE		187,172,203	67,261,316	3,229,819	49,263,759	45,309,646	172,391	5,601,187	1,901,043	3,596,333	9,464,883	1,462,848
2													
3	TOTAL AVAILABLE FOR RETURN		12,942,144	2,360,006	81,008	6,023,187	5,480,044	(5,539)	(33,185)	(183)	(79,489)	(903,248)	19,542
4													
5	RATE OF RETURN EARNED		6.91%	3.51%	2.51%	12.23%	12.09%	-3.21%	-0.59%	-0.01%	-2.27%	-9.54%	1.34%
6													
7	RATE OF RETURN REQUESTED		8.89%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%	8.89%
8													
9	OPERATING INCOME REQUIRED		16,639,698	5,979,531	287,131	4,379,546	4,028,028	15,326	497,946	169,003	311,713	841,428	130,047
10													
11	TOTAL AVAILABLE FOR RETURN		12,942,144	2,360,006	81,008	6,023,187	5,480,044	(5,539)	(33,185)	(183)	(79,489)	(903,248)	19,542
12													
13	OPERATING INCOME DEFICIENCY		3,697,554	3,619,525	206,123	(1,643,641)	(1,452,016)	20,864	531,131	169,186	391,202	1,744,676	110,595
14													
15	INCREMENTAL TAXES		2,386,449	2,336,088	133,034	(1,060,827)	(937,150)	13,466	342,799	109,195	252,487	1,126,036	71,321
16													
17	REVENUE INCREASE REQUIRED		6,084,004	5,955,613	330,157	(2,704,468)	(2,380,167)	34,330	873,930	278,381	643,689	2,670,712	181,827
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NORTH DAKOTA

OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
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LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	ELECTRIC PLANT IN SERVICE		409,987,820	145,151,909	7,035,973	108,781,567	103,139,040	348,668	11,731,668	4,204,840	7,207,664	19,309,079	3,077,412
2	ACCUMULATED DEPRECIATION		(189,745,794)	(65,842,151)	(3,229,408)	(50,777,760)	(50,059,998)	(144,702)	(5,124,486)	(1,968,096)	(3,067,376)	(8,172,774)	(1,359,030)
3	NET PLANT EXCLUDING BIG STONE PLANT CAPITALIZED ITEMS		220,242,036	79,309,758	3,806,565	58,003,807	53,079,041	203,966	6,607,183	2,236,744	4,140,286	11,136,305	1,718,382
4	NET CAPITALIZED ITEMS - BIG STONE PLANT		118,635	33,808	1,858	33,814	44,444	0	1,570	1,348	501	775	517
5	NET ELECTRIC PLANT IN SERVICE		220,360,672	79,343,566	3,808,423	58,037,621	53,123,485	203,966	6,608,753	2,238,092	4,140,787	11,137,080	1,718,899
6	PLANT HELD FOR FUTURE USE		12,871	5,168	238	3,169	1,979	21	572	119	389	1,076	140
7	CONSTRUCTION WORK IN PROGRESS		2,257,935	935,970	41,101	543,583	337,745	3,710	98,371	20,726	69,820	182,144	24,705
8	MATERIALS AND SUPPLIES		5,722,628	2,091,786	100,757	1,489,830	1,274,482	6,284	193,525	57,003	122,452	387,465	49,043
9	FUEL STOCKS		3,072,173	865,984	47,872	871,180	1,166,335	0	41,690	34,894	13,642	16,684	13,893
10	PREPAYMENTS		(13,256,872)	(4,775,299)	(229,114)	(3,491,536)	(3,195,903)	(12,271)	(397,582)	(134,643)	(249,109)	(670,005)	(103,409)
11	CUSTOMER ADVANCES		(54,286)	(19,546)	(938)	(14,298)	(13,087)	(59)	(1,628)	(651)	(1,020)	(2,744)	(423)
12	CASH WORKING CAPITAL		1,593,584	529,293	23,808	394,565	459,316	850	33,395	15,901	20,840	107,788	13,829
13	ACCUMULATED DEFERRED INCOME TAXES		(32,540,502)	(11,716,697)	(562,387)	(8,570,374)	(7,844,707)	(30,119)	(975,910)	(330,497)	(611,467)	(1,844,605)	(253,829)
14	UNAMORTIZED BALANCE - SPIRITWOOD		0	0	0	0	0	0	0	0	0	0	0
15	UNAMORTIZED RATE CASE EXPENSE		0	0	0	0	0	0	0	0	0	0	0
16	TOTAL AVERAGE RATE BASE		187,175,203	67,261,316	3,229,819	49,263,789	45,309,646	172,391	5,801,187	1,901,043	3,506,333	9,464,683	1,462,848

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LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
PLANT IN SERVICE													
1	PRODUCTION PLANT												
2	AC 101 & 106 - BASE DEMAND	E1	105,413,237	28,101,845	1,998,211	29,134,538	42,633,395	0	1,605,385	1,194,593	581,011	0	563,269
3	PEAK DEMAND	D1	48,430,531	15,739,879	810,843	14,714,929	15,000,454	0	430,643	553,578	68,753	1,004,596	106,867
4	BASE ENERGY	E1	0	0	0	0	0	0	0	0	0	0	0
5													
6													
7	SUBTOTAL AC 101 & 106		153,843,768	43,841,724	2,410,054	43,849,466	57,633,849	0	2,036,029	1,748,161	649,765	1,004,596	670,136
8													
9	AC 114 - BASE DEMAND	E1	437,807	116,714	6,642	121,003	177,067	0	6,668	4,961	2,413	0	2,339
10	PEAK DEMAND	D1	202,575	65,837	3,392	61,550	62,744	0	1,801	2,316	288	4,202	447
11	BASE ENERGY	E1	0	0	0	0	0	0	0	0	0	0	0
12													
13													
14	SUBTOTAL AC 114		640,382	182,551	10,034	182,553	239,811	0	8,469	7,277	2,701	4,202	2,786
15													
16	TOTAL PRODUCTION PLANT	P10	154,484,150	44,024,274	2,420,087	44,032,019	57,873,659	0	2,044,498	1,755,437	652,466	1,008,798	672,922
17													
18	TRANSMISSION PLANT												
19	AC 101 & 106	D2	83,840,043	27,250,863	1,403,833	25,475,340	25,970,677	0	745,584	958,424	119,035	1,739,285	185,021
20	AC 114	D2	23,048	7,815	403	7,307	7,448	0	214	275	34	489	53
21													
22	TOTAL TRANSMISSION PLANT		83,873,091	27,258,679	1,404,236	25,483,647	25,978,125	0	745,798	958,698	119,069	1,739,764	185,074
23													
24	DISTRIBUTION PLANT												
25	PRIMARY DEMAND	D3	44,470,444	11,035,720	846,361	11,945,711	9,204,460	145,408	796,956	371,081	1,328,038	7,734,729	1,058,981
26	SECONDARY DEMAND	D2	23,731,703	5,761,354	656,241	6,441,189	3,171,600	80,023	298,099	197,270	1,572,118	4,907,636	646,174
27	PRIMARY CUSTOMER	C2	25,643,355	19,693,162	486,959	5,064,757	59,921	29,533	14,124	244,822	7,704	36,381	5,992
28	SECONDARY CUSTOMER	C3	26,434,766	20,305,004	481,467	5,240,969	58,253	30,490	14,563	252,428	7,944	37,511	6,178
29	STREET LIGHTING	C4	5,041,487	0	0	0	0	0	5,041,487	0	0	0	0
30	AREA LIGHTING	C5	2,083,462	0	0	0	0	0	2,083,462	0	0	0	0
31	METERS	C6	8,612,975	2,975,793	220,194	2,467,643	121,167	34,247	7,013	106,757	1,278,830	1,238,671	162,659
32	LOAD MANAGEMENT	C9	3,999,084	822,882	9,308	8,422	0	4,211	0	0	1,676,358	1,337,718	137,185
33													
34	TOTAL DISTRIBUTION PLANT	P60	140,016,287	60,595,914	2,683,530	31,186,691	12,615,401	323,872	8,255,714	1,172,358	5,870,992	15,292,646	2,017,169
35													
36													
37	GENERAL PLANT												
38	PRODUCTION	P10	10,736,423	3,059,623	168,193	3,060,161	4,022,135	0	142,090	122,000	45,345	70,109	46,767
39	TRANSMISSION	D2	4,290,841	1,394,519	71,839	1,303,711	1,329,008	0	38,154	49,046	6,091	89,004	9,468
40	DISTRIBUTION	P60	7,733,447	3,346,863	148,218	1,722,629	696,780	17,888	455,984	64,752	324,269	844,651	111,413
41	CUSTOMER ACCOUNTS	OX	5,554,087	3,916,788	88,343	1,227,760	17,370	4,845	2,721	50,567	125,225	107,109	13,361
42	CUSTOMER SERVICE & INFO	OX	1,525,474	823,148	22,748	324,784	244,736	656	9,526	14,717	8,600	68,333	8,226
43	LOAD MANAGEMENT	C9	59,524	12,281	139	125	0	63	0	0	24,958	19,916	2,042
44													
45	TOTAL GENERAL PLANT	P90	29,897,795	12,553,222	489,479	7,639,170	6,310,029	23,451	648,474	301,082	534,489	1,199,122	191,278
46													
47													
48	INTANGIBLE PLANT												
49		P90	1,714,497	719,820	28,641	438,041	361,826	1,345	37,184	17,264	30,648	68,759	10,968
50													
51	TOTAL PLANT IN SERVICE	EPIS	409,897,820	145,151,909	7,035,973	108,781,567	103,139,040	348,668	11,731,668	4,204,840	7,207,664	19,309,079	3,077,412
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OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
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LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	ACCUMULATED DEPRECIATION												
2	PRODUCTION PLANT												
3	BASE DEMAND	E1	(56,255,740)	(14,997,074)	(853,449)	(15,548,189)	(22,752,106)	0	(856,744)	(637,511)	(310,068)	0	(300,599)
4	PEAK DEMAND	D1	(31,285,645)	(10,167,156)	(623,763)	(9,505,091)	(9,689,526)	0	(278,174)	(357,583)	(44,411)	(648,911)	(69,031)
5	BASE ENERGY	E1	0	0	0	0	0	0	0	0	0	0	0
6													
7	TOTAL PRODUCTION PLANT		(87,539,385)	(25,164,230)	(1,377,212)	(25,053,280)	(32,441,632)	0	(1,134,917)	(995,094)	(354,479)	(648,911)	(369,630)
8													
9	TRANSMISSION PLANT	D2	(31,502,500)	(10,239,284)	(527,427)	(9,571,587)	(9,757,312)	0	(380,120)	(360,084)	(44,722)	(653,451)	(69,513)
10													
11													
12	DISTRIBUTION PLANT	P60	(58,378,187)	(25,264,772)	(1,110,867)	(13,003,767)	(5,259,847)	(135,039)	(3,442,126)	(488,801)	(2,447,843)	(6,376,093)	(841,039)
13													
14													
15	GENERAL PLANT	P90	(11,844,076)	(4,972,653)	(197,856)	(3,026,071)	(2,489,564)	(9,290)	(256,877)	(119,266)	(211,725)	(475,003)	(75,770)
16													
17													
18	INTANGIBLE PLANT	P90	(481,635)	(202,211)	(8,046)	(123,054)	(101,644)	(379)	(10,446)	(4,850)	(8,610)	(19,316)	(3,081)
19													
20													
21													
22	TOTAL ACCUMULATED DEPRECIATION		(189,745,784)	(65,842,151)	(3,229,408)	(50,777,760)	(50,059,998)	(144,702)	(5,124,486)	(1,968,096)	(3,067,378)	(8,172,774)	(1,359,039)
23													
24	NET PLANT EXCLUDING BSP CAPITALIZED ITEMS		220,242,036	79,309,758	3,800,505	58,003,807	53,079,041	203,966	6,607,183	2,236,744	4,140,286	11,136,305	1,718,382
25													
26													
27	BSP CAPITALIZED ITEMS	P10	118,635	33,808	1,858	33,814	44,444	0	1,570	1,348	501	775	517
28													
29													
30													
31	TOTAL NET PLANT IN SERVICE	NEPIS	220,360,672	79,343,566	3,808,423	58,037,621	53,123,485	203,966	6,608,753	2,238,092	4,140,787	11,137,080	1,718,899
32													
33													
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39													
40	PLANT HELD FOR FUTURE USE												
41	PRODUCTION PLANT	P10	0	0	0	0	0	0	0	0	0	0	0
42	TRANSMISSION PLANT	D2	3,729	1,212	62	1,133	1,155	0	33	43	5	77	8
43	DISTRIBUTION PLANT	P60	9,142	3,957	175	2,036	824	21	539	77	383	999	132
44	GENERAL PLANT	P90	0	0	0	0	0	0	0	0	0	0	0
45	INTANGIBLE PLANT	P90	0	0	0	0	0	0	0	0	0	0	0
46													
47	TOTAL PLANT HELD FOR FUTURE USE		12,871	5,168	238	3,169	1,979	21	572	119	389	1,076	140
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LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	CONST WORK-IN-PROGRESS - MAJOR PROJECTS	P10											
2	PRODUCTION PLANT	D2	0	0	0	0	0	0	0	0	0	0	0
3	TRANSMISSION PLANT	P60	0	0	0	0	0	0	0	0	0	0	0
4	DISTRIBUTION PLANT	P60	0	0	0	0	0	0	0	0	0	0	0
5	GENERAL PLANT	P90	0	0	0	0	0	0	0	0	0	0	0
6	INTANGIBLE PLANT	P90	0	0	0	0	0	0	0	0	0	0	0
7													
8	TOTAL CMP - MAJOR PROJECTS		0	0	0	0	0	0	0	0	0	0	0
9													
10	CONST WORK-IN-PROGRESS - SHORT-TERM	P10											
11	PRODUCTION PLANT	D2	58,452	16,658	916	16,660	21,898	0	774	664	247	382	255
12	TRANSMISSION PLANT	P60	237,147	77,072	3,970	72,054	73,452	0	2,109	2,711	337	4,919	523
13	DISTRIBUTION PLANT	P60	1,419,997	614,543	27,215	316,305	127,941	3,285	83,727	11,890	59,542	155,093	20,457
14	GENERAL PLANT	P90	542,389	227,697	9,060	138,563	114,455	425	11,762	5,461	9,695	21,750	3,470
15	INTANGIBLE PLANT	P90	0	0	0	0	0	0	0	0	0	0	0
16													
17													
18	TOTAL CMP - SHORT-TERM		2,257,935	935,970	41,161	543,583	337,745	3,710	98,371	20,726	69,820	182,144	24,705
19													
20	CONST WORK-IN-PROGRESS - LONG-TERM	P10											
21	PRODUCTION PLANT	D2	0	0	0	0	0	0	0	0	0	0	0
22	TRANSMISSION PLANT	P60	0	0	0	0	0	0	0	0	0	0	0
23	DISTRIBUTION PLANT	P60	0	0	0	0	0	0	0	0	0	0	0
24	GENERAL PLANT	P90	0	0	0	0	0	0	0	0	0	0	0
25	INTANGIBLE PLANT	P90	0	0	0	0	0	0	0	0	0	0	0
26													
27													
28	TOTAL CMP - LONG TERM		0	0	0	0	0	0	0	0	0	0	0
29													
30	TOTAL CONSTRUCTION WORK-IN-PROGRESS		2,257,935	935,970	41,161	543,583	337,745	3,710	98,371	20,726	69,820	182,144	24,705
31													
32	MATERIALS & SUPPLIES	P10											
33	PRODUCTION	D2	1,521,149	433,491	23,830	433,567	569,861	0	20,131	17,285	6,425	9,933	6,626
34	TRANSMISSION	P60	1,484,622	482,501	24,856	451,081	459,834	0	13,201	16,970	2,108	30,795	3,276
35	DISTRIBUTION	P60	2,716,857	1,175,795	52,071	605,181	244,787	6,284	160,193	22,748	113,920	296,736	39,141
36													
37													
38	TOTAL MATERIALS AND SUPPLIES		5,722,628	2,091,786	100,757	1,489,830	1,274,482	6,284	193,525	57,003	122,452	337,465	49,043
39													
40	FUEL STOCKS	E1											
41	COAL STOCKS	D1	2,267,853	604,581	34,405	626,799	917,212	0	34,538	25,700	12,500	0	12,118
42	FUEL OIL STOCKS		804,319	261,403	13,466	244,381	249,123	0	7,152	9,194	1,142	16,684	1,775
43													
44	TOTAL FUEL STOCKS		3,072,173	865,984	47,872	871,180	1,166,335	0	41,690	34,894	13,642	16,684	13,893
45													
46	PREPAYMENTS	NEPIS	(13,256,872)	(4,773,299)	(229,114)	(3,491,536)	(3,195,903)	(12,271)	(397,582)	(134,643)	(249,109)	(670,005)	(103,409)
47													
48	CUSTOMER ADVANCES	NEPIS	(54,286)	(19,546)	(938)	(14,298)	(13,087)	(59)	(1,628)	(651)	(1,020)	(2,744)	(423)
49													
50	CASH WORKING CAPITAL	OX	1,598,594	528,293	23,808	394,565	459,316	850	33,395	15,901	20,840	107,788	13,829
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LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	ACCUMULATED DEFERRED INCOME TAXES												
2	ITEMS SD FLOWS THROUGH												
3	FEDERAL		(2,064,775)	(743,447)	(35,685)	(543,811)	(487,766)	(1,911)	(61,924)	(20,971)	(38,799)	(104,354)	(16,106)
4	MINNESOTA		0	0	0	0	0	0	0	0	0	0	0
5	NORTH DAKOTA		(390,230)	(140,507)	(6,744)	(102,777)	(94,075)	(963)	(11,703)	(3,963)	(7,333)	(19,722)	(3,044)
6													
7	SUBTOTAL		(2,455,005)	(883,955)	(42,429)	(646,588)	(581,841)	(2,272)	(73,627)	(24,934)	(46,132)	(124,077)	(19,150)
8	ALL OTHER												
9	FEDERAL		(25,709,554)	(9,257,041)	(444,330)	(6,771,269)	(6,197,935)	(23,797)	(771,045)	(261,119)	(483,107)	(1,299,367)	(200,545)
10	MINNESOTA		0	0	0	0	0	0	0	0	0	0	0
11	NORTH DAKOTA		(4,375,944)	(1,575,612)	(75,626)	(1,152,517)	(1,054,931)	(4,056)	(131,237)	(44,444)	(82,226)	(221,161)	(34,134)
12													
13	SUBTOTAL		(30,085,497)	(10,832,653)	(519,956)	(7,923,785)	(7,252,866)	(27,847)	(902,283)	(305,563)	(565,335)	(1,520,528)	(234,679)
14													
15	TOTAL ACCUMULATED DEFERRED INCOME TAXES		(32,540,502)	(11,716,607)	(562,387)	(8,570,374)	(7,844,707)	(30,119)	(975,910)	(330,497)	(611,467)	(1,644,605)	(253,829)
16													
17													
18	UNAMORTIZED BALANCE - SPIRITWOOD PLANT	P10	0	0	0	0	0	0	0	0	0	0	0
19													
20													
21													
22	UNAMORTIZED RATE CASE EXPENSES	R10	0	0	0	0	0	0	0	0	0	0	0
23													
24													
25													
26													
27	TOTAL AVERAGE RATE BASE		187,173,203	67,261,316	3,229,819	49,263,739	45,309,646	172,391	5,601,187	1,901,043	3,506,333	9,464,883	1,462,848
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OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	OPERATING REVENUES		118,309,177	36,574,921	1,601,767	34,012,150	36,231,788	45,963	2,095,668	987,569	1,185,332	4,744,402	849,617
2	SALES OF ELECTRICITY		13,804,432	4,233,563	206,440	3,411,099	4,173,430	7,994	262,357	136,601	191,521	1,048,161	133,267
3	OTHER OPERATING REVENUE		132,113,609	40,808,484	1,808,207	37,423,249	40,405,218	53,957	2,358,025	1,104,170	1,376,853	5,792,563	982,884
4	TOTAL OPERATING REVENUE												
5													
6													
7	OPERATING EXPENSES		67,714,729	17,992,223	943,817	16,768,827	23,737,741	21,230	879,849	679,040	682,622	5,343,536	665,964
8	PRODUCTION EXPENSES		4,467,061	1,451,791	74,769	1,357,253	1,385,589	0	39,721	51,060	6,342	92,659	9,857
9	TRANSMISSION EXPENSES		6,727,802	2,834,686	126,263	1,460,741	501,045	15,652	723,069	37,919	269,959	631,341	84,918
10	DISTRIBUTION EXPENSES		4,728,770	3,334,768	73,215	1,045,319	34,769	4,125	2,316	43,053	106,617	91,183	11,376
11	CUSTOMER ACCOUNTING EXPENSES		2,185,290	1,179,186	32,587	465,263	350,593	939	13,046	21,062	12,300	97,889	11,784
12	CUSTOMER SERVICE AND INFORMATION EXPENSES		701,476	545,831	11,270	135,740	1,513	332	300	6,705	954	2,768	443
13	SALES EXPENSES		13,557,519	5,687,143	226,455	3,457,842	2,799,888	10,941	432,187	136,689	227,720	496,204	82,451
14	ADMINISTRATIVE AND GENERAL EXPENSES		114,816	68,013	1,945	21,890	248	54	52	1,098	91	453	72
15	CHARITABLE CONTRIBUTIONS		10,715,072	3,639,474	184,123	2,908,019	2,633,436	9,808	320,991	108,859	202,040	524,804	84,519
16	DEPRECIATION EXPENSE		0	0	0	0	0	0	0	0	0	0	0
17	AMORTIZATION OF BIG STONE PLANT CAPITALIZED COSTS		0	0	0	0	0	0	0	0	0	0	0
18	SPIRITWOOD AMORTIZATION		3,957,594	1,424,980	66,388	1,042,334	954,078	3,663	118,691	40,195	74,367	200,018	30,871
19	GENERAL TAXES		114,871,140	38,377,304	1,744,762	28,591,228	32,376,918	66,745	2,532,843	1,145,700	1,582,632	7,480,855	982,155
20	TOTAL OPERATING EXPENSES												
21													
22													
23													
24	NET OPERATING INCOME BEFORE INCOME TAXES		17,242,469	2,431,180	63,445	8,842,021	8,028,300	(12,787)	(174,818)	(41,531)	(205,779)	(1,888,292)	729
25													
26													
27													
28	INCOME TAX EXPENSE		(476,371)	(168,654)	(8,175)	(126,395)	(119,839)	(405)	(13,631)	(4,886)	(8,375)	(22,436)	(3,576)
29	INVESTMENT TAX CREDIT		213,186	76,760	3,664	56,148	51,394	197	6,394	2,165	4,006	10,774	1,663
30	DEFERRED INCOME TAXES		4,563,511	163,068	(13,072)	2,889,081	2,616,701	(7,041)	(134,395)	(38,627)	(121,921)	(773,383)	(16,900)
31	INCOME TAXES		4,300,325	71,174	(17,563)	2,818,834	2,548,256	(7,249)	(141,632)	(41,347)	(126,290)	(785,044)	(18,813)
32	TOTAL INCOME TAX EXPENSE												
33													
34													
35													
36	NET OPERATING INCOME		12,842,144	2,360,006	81,008	6,023,187	5,480,044	(5,539)	(33,185)	(183)	(79,489)	(903,246)	19,542
37													
38													
39	ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION		0	0	0	0	0	0	0	0	0	0	0
40													
41													
42	TOTAL AVAILABLE FOR RETURN		12,842,144	2,360,006	81,008	6,023,187	5,480,044	(5,539)	(33,185)	(183)	(79,489)	(903,246)	19,542
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OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	OPERATING REVENUES												
2													
3	SALES OF ELECTRICITY	R10	118,309,177	36,574,921	1,601,767	34,012,150	36,231,788	45,963	2,095,668	967,569	1,185,332	4,744,402	849,617
4													
5													
6	OTHER OPERATING REVENUES												
7	SALES FOR RESALE												
8	MUNICIPALITIES & OFF SYSTEM SALES												
9	NON-ASSOCIATED UTILITIES, CO-OPS & OPA												
10	BUY SELL TRANSACTIONS	D2	0	0	0	0	0	0	0	0	0	0	0
11	ALL OTHER TRANSACTIONS												
12	BASE DEMAND	E1	0	0	0	0	0	0	0	0	0	0	0
13	PEAK DEMAND	D1	0	0	0	0	0	0	0	0	0	0	0
14	BASE ENERGY	E2	8,508,499	2,214,519	115,241	2,035,926	2,961,262	3,214	111,508	82,974	96,869	793,092	93,894
15	PEAK ENERGY	D1	0	0	0	0	0	0	0	0	0	0	0
16													
17	TOTAL ALL OTHER TRANSACTIONS		8,508,499	2,214,519	115,241	2,035,926	2,961,262	3,214	111,508	82,974	96,869	793,092	93,894
18													
19	TOTAL SALES FOR RESALE		8,508,499	2,214,519	115,241	2,035,926	2,961,262	3,214	111,508	82,974	96,869	793,092	93,894
20													
21													
22	OTHER ELECTRIC REVENUES												
23	LATE FEES	C1	170,779	132,399	2,744	32,560	368	81	78	1,632	135	674	108
24	CONNECTION FEES	C1	89,754	69,583	1,442	17,112	194	43	41	888	71	354	57
25	RENT FROM ELECTRIC PROPERTY - BIG STONE	NEPIS	270,804	97,506	4,680	71,323	66,284	251	8,122	2,750	5,089	13,686	2,112
26	RENT FROM ELECTRIC PROPERTY - COYOTE	NEPIS	(6,686)	(3,128)	(150)	(2,288)	(2,094)	(6)	(261)	(89)	(1,63)	(439)	(66)
27	OTHER MISC ELECTRIC REVENUE	NEPIS	4,981	1,794	86	1,312	1,201	5	149	51	94	252	39
28	ITA DEFICIENCY PAYMENTS	NEPIS	1,333,335	480,084	23,044	351,168	321,434	1,234	39,988	13,542	25,055	67,387	10,401
29	MISCELLANEOUS SERVICES	NEPIS	1,535,611	552,916	26,539	404,443	370,198	1,421	46,054	15,596	28,856	77,610	11,978
30	WHEELING	NEPIS	14,308	5,152	247	3,768	3,449	13	429	145	269	723	112
31	LOAD CONTROL AND DISPATCH	NEPIS	1,875,405	675,263	32,412	493,936	452,114	1,736	56,245	19,048	35,241	94,783	14,629
32	RESIDENTIAL CONSERVATION SERVICES	C1	9,642	7,475	155	1,838	21	5	24	92	8	38	6
33													
34	TOTAL OTHER ELECTRIC REVENUES		5,295,933	2,019,044	91,199	1,375,172	1,212,168	4,780	150,849	53,627	94,652	255,069	39,373
35													
36	TOTAL OTHER OPERATING REVENUES		13,804,432	4,233,563	206,440	3,411,099	4,173,430	7,994	262,357	136,601	191,521	1,048,161	133,267
37													
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40													
41	TOTAL OPERATING REVENUES		132,113,609	40,808,484	1,808,207	37,423,249	40,405,218	53,957	2,388,025	1,104,170	1,376,853	5,792,953	982,884
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OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
OPERATING EXPENSES													
1	PRODUCTION EXPENSES												
2	PROD EXPENSES EXCLUDING PURCHASED POWER												
3	BASE DEMAND	E1	4,731,771	1,261,431	71,795	1,307,796	1,913,720	0	72,062	53,622	26,080	0	25,284
4	PEAK DEMAND	D1	2,467,800	798,793	41,149	746,788	761,238	0	21,855	28,094	3,489	50,982	5,423
5	BASE ENERGY	E2	26,204,212	6,820,207	354,916	6,270,133	9,120,002	9,889	343,419	265,541	288,333	2,442,540	289,171
6	PEAK ENERGY	D1	2,697,632	844,228	43,491	789,254	804,568	0	23,088	29,692	3,688	53,882	5,732
7													
8	TOTAL EXCLUDING PURCHASED POWER		35,991,415	9,724,649	511,341	9,113,991	12,599,548	9,899	460,434	386,949	331,590	2,547,404	325,611
9													
10													
11	PURCHASED POWER												
12	BUY SELL TRANSACTIONS	D2	0	0	0	0	0	0	0	0	0	0	0
13	ALL OTHER TRANSACTIONS												
14	BASE DEMAND	E1	1,725,792	460,074	26,182	476,981	697,980	0	26,263	19,557	9,512	0	9,222
15	PEAK DEMAND	D1	0	0	0	0	0	0	0	0	0	0	0
16	BASE ENERGY	E2	29,997,532	7,807,500	406,294	7,177,855	10,440,213	11,331	393,132	292,534	341,520	2,796,122	331,032
17	PEAK ENERGY	D1	0	0	0	0	0	0	0	0	0	0	0
18													
19													
20	TOTAL ALL OTHER TRANSACTIONS		31,723,324	8,267,574	432,476	7,654,836	11,136,193	11,331	419,415	312,091	351,032	2,796,122	340,254
21													
22	TOTAL PURCHASED POWER		31,723,324	8,267,574	432,476	7,654,836	11,136,193	11,331	419,415	312,091	351,032	2,796,122	340,254
23													
24	TOTAL PRODUCTION EXPENSES		67,714,739	17,992,223	943,817	16,768,827	23,737,741	21,230	879,849	679,040	682,622	5,343,526	685,864
25													
26	TRANSMISSION EXPENSES												
27		D2	4,467,061	1,451,791	74,789	1,357,253	1,383,589	0	39,721	51,000	6,342	92,659	9,857
28													
29													
30	DISTRIBUTION EXPENSES												
31	PRIMARY DEMAND	D3	1,905,348	472,828	36,391	511,817	394,368	6,230	34,146	15,899	56,900	331,397	45,372
32	SECONDARY DEMAND	D4	637,417	154,746	17,626	173,006	85,187	2,149	8,007	5,299	42,226	131,816	17,356
33	PRIMARY CUSTOMER	C2	1,303,643	1,001,150	23,739	258,496	3,046	1,501	718	12,446	392	1,850	305
34	SECONDARY CUSTOMER	C3	1,054,914	810,297	19,214	209,148	2,325	1,215	581	10,073	317	1,497	247
35	STREET LIGHTING	C4	659,874	0	0	0	0	0	659,874	0	0	0	0
36	AREA LIGHTING	C5	20,809	0	0	0	0	0	20,809	0	0	0	0
37	METERS	C6	1,145,797	395,874	29,293	328,274	16,119	4,556	933	14,202	170,125	164,782	21,639
38	LOAD MANAGEMENT	C9	0	0	0	0	0	0	0	0	0	0	0
39													
40	TOTAL DISTRIBUTION	OXD	6,727,802	2,834,896	126,263	1,480,741	501,045	15,652	725,069	57,919	269,959	631,341	84,918
41													
42													
43	CUSTOMER ACCOUNTING EXPENSES												
44	METER READING	C7	2,044,032	1,272,986	26,327	512,969	8,515	1,033	838	17,421	105,810	87,384	10,749
45	OTHER	C8	2,684,788	2,061,781	48,888	532,350	6,273	3,092	1,479	25,632	807	3,809	627
46													
47	TOTAL CUSTOMER ACCOUNTS	OXC	4,728,820	3,334,768	75,215	1,045,319	14,789	4,125	2,316	43,053	106,617	91,193	11,376
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OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	CUSTOMER SERVICE & INFORMATION EXPENSE												
2	CONSERVATION & PROMOTIONAL REBATES	E2	1,000,000	260,271	13,544	239,282	348,036	378	13,105	9,752	11,385	93,212	11,035
3	OTHER	C1	1,185,290	919,915	10,043	225,981	2,557	561	541	11,330	936	4,678	748
4													
5	TOTAL CUSTOMER SERV & INFORMATION EXP	Oxi	2,185,290	1,179,186	32,587	465,263	350,593	939	13,646	21,082	12,320	97,889	11,784
6													
7													
8	SALES EXPENSES												
9	OFF-PEAK DEVELOPMENT	C1	500,000	387,623	8,033	95,328	1,079	237	228	4,790	395	1,973	316
10	OTHER	C1	201,476	156,197	3,237	38,412	435	95	92	1,926	159	795	127
11													
12	TOTAL SALES EXPENSES		701,476	543,821	11,270	133,740	1,513	332	320	6,705	554	2,768	443
13													
14													
15	ADMINISTRATIVE & GENERAL EXPENSES												
16	SALARIES, SUPPLIES, PENSIONS & BENEFITS												
17	PRODUCTION	OXPD	3,452,775	975,067	53,877	960,422	1,305,292	0	46,551	39,221	15,136	19,744	15,464
18	TRANSMISSION	D2	1,357,755	441,269	22,732	412,535	420,539	0	12,073	15,520	1,928	28,164	2,996
19	DISTRIBUTION	OXD	2,559,933	1,079,680	48,043	563,423	190,648	5,956	275,889	22,038	102,720	240,226	32,311
20	CUSTOMER ACCOUNTS	OXD	1,803,178	1,271,616	28,681	398,602	5,639	1,573	883	16,417	40,655	34,774	4,338
21	CUSTOMER SERVICE & INFO	C1	631,311	489,434	10,143	120,363	1,362	299	288	6,035	498	2,491	399
22													
23	TOTAL SALARIES, SUPPLIES, PENSIONS, AND BENEFITS		9,804,952	4,257,065	163,476	2,475,344	1,924,480	7,827	335,685	99,231	160,936	325,399	55,508
24													
25	LOAD MANAGEMENT EXPENSES	C9	0	0	0	0	0	0	0	0	0	0	0
26													
27	OUTSIDE SERVICES	NEPIS	726,210	261,481	12,551	191,266	175,071	672	21,779	7,376	13,646	36,703	5,665
28													
29	PROPERTY INSURANCE	NEPIS	529,778	190,753	9,156	138,531	127,716	490	15,888	5,381	9,955	26,775	4,132
30													
31	INJURIES & DAMAGES	NEPIS	692,354	249,291	11,966	182,349	166,909	641	20,764	7,032	13,010	34,992	5,401
32													
33	REGULATORY COMMISSION EXPENSE	R10	263,370	81,420	3,566	75,715	80,656	102	4,665	2,154	2,639	10,562	1,891
34													
35	GENERAL ADVERTISING	C1	606	470	10	116	1	0	0	6	0	2	0
36													
37	MISCELLANEOUS, RENTS, MAINTENANCE	P90	1,540,249	646,663	25,730	393,522	325,053	1,208	33,405	15,510	27,534	61,771	9,853
38													
39	TOTAL ADMINISTRATIVE & GENERAL EXP		13,557,519	5,687,143	226,455	3,457,842	2,799,888	10,941	432,187	136,689	227,720	496,204	82,451
40													
41	CHARITABLE CONTRIBUTIONS	C1	114,816	89,013	1,845	21,890	248	54	52	1,098	91	453	72
42													
43													
44													
45	TOTAL O & M EXPENSES		100,197,474	33,112,849	1,492,241	24,730,875	28,789,404	53,274	2,093,161	996,646	1,306,225	6,756,033	866,765
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LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	DEPRECIATION EXPENSE												
2	PRODUCTION	E1	2,895,006	771,772	43,920	800,133	1,170,858	0	44,089	32,807	15,957	0	15,469
3	BASE DEMAND	D1	1,185,906	385,418	19,855	360,321	387,312	0	10,545	13,555	1,684	24,599	2,617
4	PEAK DEMAND	E1	0	0	0	0	0	0	0	0	0	0	0
5	BASE ENERGY												
6													
7	TOTAL PRODUCTION		4,080,911	1,157,190	63,775	1,160,454	1,558,170	0	54,634	46,363	17,640	24,599	18,086
8													
9													
10	TRANSMISSION	D2	1,614,258	524,632	27,027	490,469	499,986	0	14,354	19,452	2,292	33,484	3,562
11													
12													
13	DISTRIBUTION	P90	3,839,335	1,661,578	73,584	855,214	945,922	8,881	226,377	32,147	160,986	419,334	55,312
14													
15													
16	GENERAL	P90	946,193	397,252	15,806	241,745	199,684	742	20,521	9,528	16,914	37,947	6,053
17													
18													
19	INTANGIBLE	P90	235,374	96,820	3,932	60,136	48,673	185	5,105	2,370	4,208	9,440	1,506
20													
21													
22	TOTAL DEPRECIATION EXPENSE		10,716,072	3,839,474	184,123	2,808,019	2,633,436	9,808	320,991	108,859	202,040	524,804	84,519
23													
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29	BIG STONE EXPENSE OFFSETS	P10	0	0	0	0	0	0	0	0	0	0	0
30													
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32	SPIRITWOOD AMORTIZATION	P10	0	0	0	0	0	0	0	0	0	0	0
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OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	GENERAL TAXES	NEPIS	3,957,594	1,424,980	68,398	1,042,334	954,078	3,663	118,691	40,195	74,367	200,018	30,871
2	NET OPERATING INCOME BEFORE TAX (NOBT)		17,242,469	2,431,180	63,445	8,842,021	8,028,300	(12,787)	(174,818)	(41,531)	(205,779)	(1,688,292)	729
4	INVESTMENT TAX CREDIT	EPIS	(476,371)	(168,654)	(8,175)	(126,395)	(119,839)	(405)	(13,631)	(4,886)	(8,375)	(22,436)	(3,576)
5	AMORTIZE PRIOR YEARS CREDIT	EPIS	0	0	0	0	0	0	0	0	0	0	0
6	DEBITS UTILIZED		(476,371)	(168,654)	(8,175)	(126,395)	(119,839)	(405)	(13,631)	(4,886)	(8,375)	(22,436)	(3,576)
7													
8	TOTAL INVESTMENT TAX CREDIT												
9													
10	DEFERRED INCOME TAXES												
11	ITEMS SOUTH DAKOTA FLOWS THROUGH												
12	FEDERAL												
13	MINNESOTA												
14	NORTH DAKOTA												
15													
16													
17	SUB TOTAL		325,616	117,242	5,628	85,759	76,488	301	9,765	3,307	6,119	16,457	2,540
18													
19	ALL OTHER												
20	FEDERAL												
21	MINNESOTA												
22	NORTH DAKOTA												
23													
24	SUB TOTAL		(112,430)	(40,482)	(1,943)	(29,611)	(27,104)	(104)	(3,372)	(1,142)	(2,113)	(5,682)	(877)
25													
26	TOTAL DEFERRED INCOME TAXES		213,186	76,760	3,684	56,148	51,394	197	6,394	2,165	4,006	10,774	1,663
27													
28													
29	CURRENT INCOME TAXES												
30	FEDERAL INCOME TAXES		3,809,410	136,307	(10,896)	2,410,857	2,183,463	(5,876)	(112,120)	(32,224)	(101,720)	(645,285)	(14,096)
31	MINNESOTA INCOME TAXES		0	0	0	0	0	0	0	0	0	0	0
32	NORTH DAKOTA INCOME TAXES		755,101	26,761	(2,176)	478,224	433,238	(1,166)	(22,275)	(6,403)	(20,201)	(128,098)	(2,804)
33													
34	TOTAL CURRENT INCOME TAXES		4,563,511	163,068	(13,072)	2,889,081	2,616,701	(7,041)	(134,395)	(38,627)	(121,921)	(773,383)	(16,900)
35													
36	TOTAL INCOME TAXES		4,300,325	71,174	(17,563)	2,818,834	2,546,296	(7,249)	(141,632)	(41,347)	(126,290)	(785,044)	(18,813)
37													
38	NET OPERATING INCOME		12,942,144	2,360,006	81,008	6,023,187	5,480,044	(5,539)	(33,185)	(183)	(79,489)	(903,246)	19,542
39													
40	AFDC		0	0	0	0	0	0	0	0	0	0	0
41													
42	TOTAL AVAILABLE FOR RETURN	CWIP/LT	12,942,144	2,360,006	81,008	6,023,187	5,480,044	(5,539)	(33,185)	(183)	(79,489)	(903,246)	19,542
43													
44													
45	RATE OF RETURN ON RATE BASE		6.91%	3.51%	2.51%	12.23%	12.09%	-3.21%	-0.59%	-0.01%	-2.27%	-9.54%	1.34%
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LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	DEVELOPMENT OF FEDERAL INCOME TAX EXPENSE												
2	NET OPERATING INCOME BEFORE TAX (NOBIT)		17,242,469	2,431,180	63,445	8,842,021	8,026,300	(12,787)	(174,818)	(41,531)	(205,779)	(1,688,292)	729
3	LESS: INTEREST COST		5,091,111	1,829,508	87,851	1,339,974	1,232,422	4,689	152,352	51,708	95,372	257,445	39,789
4													
5	NET INCOME BEFORE TAX		12,151,358	601,672	(24,406)	7,502,047	6,795,878	(17,476)	(327,170)	(93,239)	(301,151)	(1,945,736)	(38,060)
6													
7	FEDERAL SCHEDULE M ADJUSTMENTS:												
8	ADDITIONAL TAX DEPRECIATION	NEPIS	1,135,998	409,994	19,631	299,168	273,837	1,051	34,065	11,537	21,345	57,409	8,860
9	COST TO REMOVE	NEPIS	1,660,645	597,936	28,700	437,373	400,340	1,537	49,804	16,866	31,205	83,929	12,954
10	DIRECTLY ASSIGNED SCHEDULE M ITEMS	NEPIS	(50,235)	(21,358)	(1,054)	(15,601)	(14,260)	(35)	(1,776)	(602)	(1,113)	(2,984)	(462)
11	ACCURED VACATION PAY	NEPIS	39,976	13,313	639	9,738	8,914	34	1,109	376	695	1,869	288
12	CHARGES - OPERATING RESERVES	NEPIS	1,964,501	707,343	33,952	517,402	473,593	1,818	56,917	19,952	36,915	99,286	15,324
13	PROVISIONS - OPERATING RESERVES	NEPIS	(3,615,645)	(1,301,857)	(62,468)	(952,273)	(871,642)	(3,347)	(108,435)	(36,722)	(67,941)	(182,736)	(28,203)
14	UNBILLED REVENUES	NEPIS	0	0	0	0	0	0	0	0	0	0	0
15	PREFERRED DIVIDENDS PAID CREDIT	NEPIS	67,606	24,342	1,168	17,806	16,298	63	2,028	687	1,270	3,417	527
16	OTHER SCHEDULE M ITEMS	NEPIS	(675,662)	(243,280)	(11,677)	(177,953)	(162,885)	(625)	(20,264)	(6,862)	(12,696)	(34,146)	(5,270)
17													
18	SUBTOTAL FEDERAL SCHEDULE M ADJUSTMENTS		515,086	185,463	8,902	135,661	124,175	477	15,448	5,231	9,679	26,033	4,018
19													
20	FEDERAL ADJUSTED INCOME BEFORE INCOME TAXES		11,636,272	415,209	(33,308)	7,365,386	6,671,703	(17,953)	(342,618)	(86,470)	(310,830)	(1,971,769)	(43,078)
21													
22	LESS:												
23	MINNESOTA STATE INCOME TAXES		0	0	0	0	0	0	0	0	0	0	0
24	NORTH DAKOTA STATE INCOME TAXES		755,101	26,761	(2,176)	478,224	433,238	(1,166)	(22,275)	(6,403)	(20,201)	(128,098)	(2,804)
25													
26	FEDERAL TAXABLE INCOME		10,881,171	389,448	(31,132)	6,885,162	6,238,465	(16,787)	(320,343)	(92,067)	(290,629)	(1,843,671)	(40,274)
27	FEDERAL TAX RATE		35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
28	FEDERAL INCOME TAX BEFORE CREDITS		3,808,410	136,307	(10,896)	2,410,857	2,183,463	(5,876)	(112,120)	(32,224)	(101,720)	(645,285)	(14,096)
29	INVESTMENT TAX CREDIT - DEBITS UTILIZED	EPIS	0	0	0	0	0	0	0	0	0	0	0
30													
31	FEDERAL INCOME TAXES		3,808,410	136,307	(10,896)	2,410,857	2,183,463	(5,876)	(112,120)	(32,224)	(101,720)	(645,285)	(14,096)
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LINE NO	ITEM	ALLOC	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	DEVELOPMENT OF MINNESOTA STATE INCOME TAX EXPENSE		0	0	0	0	0	0	0	0	0	0	0
2	FEDERAL ADJUSTED INCOME BEFORE INCOME TAXES		0	0	0	0	0	0	0	0	0	0	0
3	MINNESOTA ADJUSTMENTS TO FEDERAL SCHEDULE M:												
4	PAY/SOP ADJUSTMENT	NEPIS	0	0	0	0	0	0	0	0	0	0	0
5	CHANGE IN EXCESS TAX DEPRECIATION - MN	NEPIS	0	0	0	0	0	0	0	0	0	0	0
6	CHANGE IN ACRS - ORDINARY LOSS	NEPIS	0	0	0	0	0	0	0	0	0	0	0
7	PREFERRED DIVIDENDS PAID CREDIT	NEPIS	0	0	0	0	0	0	0	0	0	0	0
8	MISCELLANEOUS ADJUSTMENTS TO FED SCHEDULE M	NEPIS	0	0	0	0	0	0	0	0	0	0	0
9			0	0	0	0	0	0	0	0	0	0	0
10			0	0	0	0	0	0	0	0	0	0	0
11			0	0	0	0	0	0	0	0	0	0	0
12	TOTAL MINNESOTA ADJUSTMENTS TO FED SCHEDULE M		0	0	0	0	0	0	0	0	0	0	0
13	MINNESOTA TAXABLE INCOME		0	0	0	0	0	0	0	0	0	0	0
14	MINNESOTA TAX RATE		0	0	0	0	0	0	0	0	0	0	0
15			0	0	0	0	0	0	0	0	0	0	0
16	MINNESOTA INCOME TAX		0	0	0	0	0	0	0	0	0	0	0
17			0	0	0	0	0	0	0	0	0	0	0
18			0	0	0	0	0	0	0	0	0	0	0
19			0	0	0	0	0	0	0	0	0	0	0
20			0	0	0	0	0	0	0	0	0	0	0
21			0	0	0	0	0	0	0	0	0	0	0
22			0	0	0	0	0	0	0	0	0	0	0
23			0	0	0	0	0	0	0	0	0	0	0
24			0	0	0	0	0	0	0	0	0	0	0
25			0	0	0	0	0	0	0	0	0	0	0
26			0	0	0	0	0	0	0	0	0	0	0
27	DEVELOPMENT OF NORTH DAKOTA STATE INCOME TAX EXPENSE		11,636,272	418,209	(33,348)	7,366,386	6,671,703	(17,953)	(342,618)	(98,470)	(310,830)	(1,971,769)	(43,078)
28	FEDERAL ADJUSTED INCOME BEFORE INCOME TAXES												
29	NORTH DAKOTA ADJUSTMENTS TO FEDERAL SCHEDULE M:												
30	CHANGE IN EXCESS TAX DEPRECIATION - ND	NEPIS	(7,783)	(2,802)	(135)	(2,050)	(1,876)	(7)	(233)	(79)	(146)	(393)	(61)
31	CHANGE IN ACRS - ORDINARY LOSS - ND	NEPIS	0	0	0	0	0	0	0	0	0	0	0
32	CHANGE IN INCOME FROM ADR PROPERTY - ND	NEPIS	0	0	0	0	0	0	0	0	0	0	0
33	MISCELLANEOUS ADJUSTMENTS TO FED SCHEDULE M	NEPIS	(3,785)	(1,363)	(65)	(997)	(912)	(4)	(113)	(38)	(71)	(191)	(30)
34			0	0	0	0	0	0	0	0	0	0	0
35	TOTAL NORTH DAKOTA ADJUSTMENTS TO FED SCHEDULE M		(11,567)	(4,165)	(200)	(3,047)	(2,789)	(11)	(347)	(117)	(217)	(685)	(90)
36	SUBTOTAL		11,624,704	412,044	(33,508)	7,363,340	6,668,915	(17,964)	(342,965)	(98,589)	(311,048)	(1,972,354)	(43,168)
37	DEDUCTION OF FEDERAL INCOME TAXES		0	0	0	0	0	0	0	0	0	0	0
38			0	0	0	0	0	0	0	0	0	0	0
39			0	0	0	0	0	0	0	0	0	0	0
40	NORTH DAKOTA TAXABLE INCOME		11,624,704	412,044	(33,508)	7,363,340	6,668,915	(17,964)	(342,965)	(98,589)	(311,048)	(1,972,354)	(43,168)
41	NORTH DAKOTA TAX RATE		6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%	6.50%
42			755,101	26,761	(2,176)	478,224	433,238	(1,166)	(22,275)	(6,403)	(20,201)	(128,098)	(2,904)
43	NORTH DAKOTA INCOME TAX												
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OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

NORTH DAKOTA

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LINE NO	ITEM	ALLOCATION FACTOR	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
1	MWH CONSUMPTION AT GENERATORS - PARTIAL PERCENTAGE	E1	1,621,989 100.00000%	432,402 26.65874%	24,607 1.51709%	448,292 27.63841%	655,988 40.44406%	0 0.00000%	24,702 1.52394%	18,381 1.13224%	8,940 0.55117%	0 0.00000%	8,667 0.53434%
2													
3	MWH CONSUMPTION AT GENERATORS - TOTAL PERCENTAGE	E2	1,884,869 100.00000%	490,575 26.07141%	25,529 1.35442%	451,012 23.92815%	655,988 34.80857%	712 0.03777%	24,702 1.31055%	18,381 0.97519%	21,459 1.13849%	175,691 9.32177%	20,800 1.10353%
4													
5													
6	GENERATION DEMAND FACTOR PERCENTAGE	D1	259,222 100.00000%	84,247 32.49891%	4,340 1.67424%	78,761 30.38558%	80,289 30.97313%	0 0.00000%	2,305 0.88820%	2,983 1.14303%	368 0.14196%	5,377 2.07428%	572 0.22666%
7													
8													
9	TRANSMISSION DEMAND FACTOR PERCENTAGE	D2	259,222 100.00000%	84,247 32.49891%	4,340 1.67424%	78,761 30.38558%	80,289 30.97313%	0 0.00000%	2,305 0.88820%	2,983 1.14303%	368 0.14196%	5,377 2.07428%	572 0.22666%
10													
11													
12	DISTRIBUTION - PRIMARY DEMAND FACTOR PERCENTAGE	D3	335,193 100.00000%	83,181 24.81585%	6,402 1.90994%	90,040 26.86214%	69,378 20.69793%	1,096 0.32686%	6,007 1.79210%	2,797 0.83444%	10,010 2.98634%	59,300 17.59246%	7,982 2.38131%
13													
14													
15	DISTRIBUTION - SECONDARY DEMAND FACTOR PERCENTAGE	D4	459,669 100.00000%	111,594 24.27703%	12,711 2.76525%	124,762 27.14170%	61,432 13.36440%	1,550 0.33720%	5,774 1.25612%	3,821 0.83125%	30,451 6.62655%	95,058 20.87986%	12,516 2.72533%
16													
17													
18													
19	CUSTOMER OR METER FACTORS												
20	TOTAL RETAIL CUSTOMERS PERCENTAGE	C1	57,014 100.00000%	44,201 77.52677%	916 1.60662%	10,870 19.06549%	123 0.21574%	27 0.04736%	26 0.04560%	545 0.95591%	45 0.07893%	225 0.39464%	36 0.06314%
21													
22													
23	RETAIL SERVICE LOCATIONS PERCENTAGE	C2	59,913 100.00000%	46,011 76.79635%	1,091 1.82097%	11,880 19.82875%	140 0.23367%	69 0.11517%	33 0.05508%	572 0.95472%	18 0.03004%	85 0.14187%	14 0.02337%
24													
25													
26	SECONDARY SERVICE LOCATIONS PERCENTAGE	C3	59,901 100.00000%	46,011 76.81174%	1,091 1.82134%	11,876 19.82605%	132 0.22038%	69 0.11519%	33 0.05509%	572 0.95491%	18 0.03005%	85 0.14190%	14 0.02337%
27													
28													
29	STREET LIGHTING FACTOR PERCENTAGE	C4	1,760,035 100.00000%	0 0.00000%	0 0.00000%	0 0.00000%	0 0.00000%	0 0.00000%	1,760,035 100.00000%	0 0.00000%	0 0.00000%	0 0.00000%	0 0.00000%
30													
31													
32	AREA LIGHTING FACTOR PERCENTAGE	C5	1,716,671 100.00000%	0 0.00000%	0 0.00000%	0 0.00000%	0 0.00000%	0 0.00000%	1,716,671 100.00000%	0 0.00000%	0 0.00000%	0 0.00000%	0 0.00000%
33													
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35	METER FACTOR PERCENTAGE	C6	12,850,789 100.00000%	4,439,942 34.55011%	328,536 2.55654%	3,681,789 28.65030%	180,785 1.40680%	51,098 0.39763%	10,464 0.08143%	159,285 1.23950%	1,908,048 14.84771%	1,848,130 14.38145%	242,692 1.88554%
36													
37													
38	METER READING FACTOR PERCENTAGE	C7	73,215 100.00000%	45,597 62.27822%	943 1.28799%	18,374 25.09595%	305 0.41658%	37 0.05054%	30 0.04098%	624 0.85228%	3,790 5.17653%	3,130 4.27508%	385 0.52585%
39													
40													
41	SYSTEM SERVICE LOCATIONS PERCENTAGE	C8	59,913 100.00000%	46,011 76.79635%	1,091 1.82097%	11,880 19.82875%	140 0.23367%	69 0.11517%	33 0.05508%	572 0.95472%	18 0.03004%	85 0.14187%	14 0.02337%
42													
43													
44	LOAD MANAGEMENT FACTOR PERCENTAGE	C9	18,040 100.00000%	3,722 20.63195%	42 0.23282%	38 0.21064%	0 0.00000%	19 0.10532%	0 0.00000%	0 0.00000%	7,564 41.92505%	6,036 33.45888%	619 3.43126%
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NORTH DAKOTA

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OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2007 ACTUAL WITH KNOWN AND MEASURABLE CHANGES

LINE NO	ITEM	ALLOCATION FACTOR	NORTH DAKOTA	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED
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2007 Test Year work papers

Functionalization

Line #		DESCRIPTION	ACCOUNTS	OPERATING STATEMENT AMOUNTS TEST YEAR 2007	2007	FUNCTIONALIZATION	Page 2 of 6
1	2		3				
STEAM POWER GENERATION:							
1		SUPERVISION AND ENGINEERING	401 - 500	1,394,608			
2		FUEL	401 - 501	55,008,518			
3		STEAM EXPENSE	401 - 502	3,191,009			
4		ELECTRICAL EXPENSE	401 - 505	2,500,200			
5		MISCELLANEOUS EXPENSE	401 - 506	4,140,261			
6		RENT	401 - 507	3,216			
7							
8							
9		STEAM POWER MAINTENANCE:					
10		SUPERVISION AND ENGINEERING	402 - 510	695,172			
11		STRUCTURES	402 - 511	605,164			
12		BOILER	402 - 512	5,918,965			
13		ELECTRIC	402 - 513	687,113			
14		MISCELLANEOUS	402 - 514	800,370			
15							
16		HYDRO:					
17		SUPERVISION AND ENGINEERING	401 - 535	65,688			
18		ELECTRIC EXPENSE	401 - 538	59,043			
19		MISCELLANEOUS EXPENSE	401 - 539	3,558			
20		SUPERVISION & ENGINEERING	402 - 541	280			
21		STRUCTURES	402 - 542	4,846			
22		RESERVOIRS - DAMS	402 - 543	417,502			
23		ELECTRIC	402 - 544	39,688			
24		MISCELLANEOUS EXPENSE	402 - 545	18,991			
25							
26		IC:					
27		SUPERVISION AND ENGINEERING	401 - 546	37,444			
28		FUEL	401 - 547	6,236,150			
29		GENERATION EXPENSE	401 - 548	622,259			
30		MISCELLANEOUS EXPENSE	401 - 549	68,914			
31		RENTS	401 - 550	3,647			
32		SUPERVISION AND ENGINEERING	402 - 551	46,967			
33		STRUCTURES	402 - 552	3,337			
34		GENERATING AND ELECTRIC	402 - 553	1,191,492			
35		MISCELLANEOUS EXPENSE	402 - 554	12,313			
36							
37		OTHER POWER SUPPLY EXPENSES:					
38		SYSTEM CONTROL AND DISPATCH	401 - 556	259,924			
39		OTHER EXPENSES	401 - 557	1,847,801			
40							
41		TRANSMISSION EXPENSES:					
42		SUPERVISION AND ENGINEERING	401 - 560	511,139			
43		LOAD DISPATCHING	401 - 561	2,791,737			
44		STATION EXPENSE	401 - 562	160,433			
45		OVERHEAD LINES	401 - 563	540,237			
46		TRANSMISSION OF ELECTRICITY BY OTHERS	401 - 565	10,283			
47		MISCELLANEOUS EXPENSE	401 - 566	1,018,264			
48		RENTS	401 - 567	40,143			
49		SUPERVISION AND ENGINEERING	402 - 568	403,322			
50		COMPUTER HARDWARE, SOFTWARE, ETC	402 - 569	752,317			
51		STATION EQUIPMENT	402 - 570	1,143,012			
52		OVERHEAD SYSTEM	402 - 571	1,630,625			
53		UNDERGROUND LINES	402 - 572	308			
54		MAINTENANCE OF MISCELLANEOUS PLANT	402 - 573	0			
55		DAY-AHEAD & REAL-TIME AND TRANSMISSION MARKET EXPENSE	401 - 575	1,435,087			
56		COMPUTER SOFTWARE	402 - 576	56,085			
57							
58		DISTRIBUTION EXPENSE:					
59		OPERATION, SUPERVISION & ENGINEERING	401 - 580	522,846			
60		LOAD DISPATCHING	401 - 581	295,848			
61		STATION EXPENSES	401 - 582	145,438			
62		LINE EXPENSES	401 - 583	330,930			
63		UNDERGROUND LINE EXPENSES	401 - 584	1,099,905			
64		STREETLIGHTING & SIGNAL SYSTEM	401 - 585	0			
65							
66		NOT USED	401 - 586.01	0			
67		NOT USED	401 - 586.02	0			
68		NOT USED	401 - 586.03	0			
69		NOT USED	401 - 586.04	0			
70		NOT USED	401 - 586.05	0			
71		NOT USED	401 - 586.06	0			
72		NOT USED	401 - 586.07	0			
73		METER EXPENSES:					
74		OTHER DISTRIBUTION EXPENSES	401 - 586	1,000,585			
75		MISCELLANEOUS DISTRIBUTION EXPENSES	401 - 587	327,862			
76		RENTS	401 - 588	2,274,823			
77		MAINTENANCE, SUPERVISION & ENGINEERING	402 - 590	813,410			
78		MAINTENANCE OF STATION EQUIPMENT	402 - 592	832,021			
79		MAINTENANCE OF OVERHEAD LINES	402 - 593	4,337,893			
80		MAINTENANCE OF UNDERGROUND LINES	402 - 594	829,638			
81		MAINTENANCE OF LINE TRANSFORMERS	402 - 595	0			
82		MAINTENANCE OF STREETLIGHTING & SIGNAL	402 - 596	992,747			
83		MAINTENANCE OF METERS.	402 - 597	441,438			
84		NOT USED	402 - 597.01	0			
85		NOT USED	402 - 597.02	0			
86		NOT USED	402 - 597.03	0			
87		MAINTENANCE OF PROPERTY IN A/C 371	402 - 598	0			
88							
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177							

401 = 65,997,811.67

402 = 8,706,782.69

401 = 128,288.84

402 = 481,307.52

401 = 6,968,413.79

402 = 1,256,128.75

Production 401 = 73,094,514.30

Production 402 = 10,444,218.96

401 = 2,107,724.20

401 = 6,507,322.71

402 = 3,985,969.49

401 = 6,239,201.96

402 = 8,447,147.21

(2) Oracle GL865A FEED Trial Balance Report

Line #		DESCRIPTION	ACCOUNTS		(2) STATEMENT AMOUNTS TEST YEAR 2007	2007	FUNCTIONALIZATION	Page 3 of 6	Line #
1		CUSTOMER ACCOUNTING:	401 - 901		192,629				1
2		SUPERVISION	401 - 902		4,569,617				2
3		METER READING EXPENSES	401 - 903		4,713,170				3
4		CUSTOMER RECORDS & COLLECTION EXPENSE	401 - 904		684,000				4
5		UNCOLLECTIBLE ACCOUNTS	401 - 905		347,844				5
6		MISCELLANEOUS EXPENSES						10,507,259.66	6
7									7
8		CUSTOMER SERVICE AND INFORMATION EXPENSE:	401 - 907		727,164				8
9		SUPERVISION	401 - 908		1,487,537				9
10		CUSTOMER ASSISTANCE EXPENSES	401 - 908.2		0				10
11		NOT USED	401 - 908.3		0				11
12		NOT USED	401 - 908.4		0				12
13		NOT USED	401 - 908.11		0				13
14		NOT USED	401 - 908.12		0				14
15		NOT USED	401 - 908.13		0				15
16		NOT USED	401 - 908.16		0				16
17		NOT USED	401 - 908.17		0				17
18		CONSERVATION INVESTMENT PROGRAM - SD	401 - 908.18		2,618,980				18
19		CONSERVATION INVESTMENT PROGRAM - ND	401 - 908.22		0				19
20		CONSERVATION INVESTMENT PROGRAM - MN	401 - 909		327,300				20
21		NOT USED	401 - 910		80,719				21
22		INFO & INSTR ADVERTISING EXPENSE							22
23		MISCELLANEOUS EXPENSES							23
24									24
25									25
26		SALES EXPENSES:	401 - 911		0				26
27		SUPERVISORY LABOR AND EXPENSES	401 - 912		427,508				27
28		NORTH DAKOTA ECONOMIC DEVELOPMENT	401 - 912.04		0				28
29		NOT USED	401 - 912		376,182				29
30		EXPENSES - SALES & DEMONSTRATIONS	401 - 912.10		0				30
31		NOT USED	401 - 912.11 & 12		0				31
32		NOT USED	401 - 912.13		0				32
33		NOT USED	401 - 912.14		0				33
34		NOT USED	401 - 912.20		0				34
35		NOT USED	401 - 912.21 & 22		0				35
36		NOT USED	401 - 912.23		0				36
37		NOT USED	401 - 912.24		0				37
38		NOT USED	401 - 912.30		0				38
39		NOT USED	401 - 912.32		0				39
40		NOT USED	401 - 912.33		0				40
41		NOT USED	401 - 912.34		0				41
42		NOT USED							42
43		ADVERTISING	401 - 913		299,289				43
44		MISCELLANEOUS SALES EXPENSE	401 - 916		318,260				44
45		NOT USED	401 - 916.02		0				45
46		NOT USED	401 - 916.03		0				46
47		NOT USED	401 - 916.04		0				47
48		NOT USED	401 - 916.08		0				48
49		NOT USED	401 - 916.10		0				49
50		NOT USED	401 - 916.11		0				50
51		NOT USED	401 - 916.12		0				51
52		NOT USED	401 - 916.13		0				52
53		NOT USED	401 - 916.20		0				53
54		NOT USED	401 - 916.21		0				54
55		NOT USED	401 - 916.22		0				55
56		NOT USED	401 - 916.23		0				56
57		NOT USED	401 - 916.30		0				57
58		NOT USED	401 - 916.31		0				58
59		NOT USED	401 - 916.32		0				59
60		NOT USED	401 - 916.33		0				60
61									61
62		OPERATING EXPENSES - ADMIN & GENERAL:	401 - 920		16,602,139				62
63		SALARIES, OFFICE SUPPLIES & EXPENSES	401 - 921		4,647,887				63
64		VARIOUS ADMIN & GENERAL EXPENSES	401 - 922		0				64
65		CAPITALIZED ADMIN & GENERAL EXPENSES	401 - 923		1,595,302				65
66		OUTSIDE SERVICES EMPLOYED	401 - 924		974,518				66
67		PROPERTY INSURANCE	401 - 925		1,646,497				67
68		INJURIES & DAMAGES	401 - 926		914,010				68
69		EMPLOYEE PENSIONS & BENEFITS	401 - 928		1,931,771				69
70		REGULATORY COMMISSION EXPENSES	401 - 930		1,296,861				70
71		MISCELLANEOUS GENERAL EXPENSES	401 - 930.01		615,095				71
72		INFORMATIONAL ADVERTISING	401 - 931		295,755				72
73		RENTS	402 - 935		2,724,986				73
74		MAINTENANCE EXPENSES			0				74
75		RADIO LOAD CONTROL EQUIPMENT	402 - 935.06		0				75

CHECK TOTALS	AMOUNTS
TOTAL 401 =	135,023,701.13
PLUS 955	74,694,689.35
TOTAL	209,718,390.48
GL TOTAL (2)	209,718,390.48
DIFFERENCE	0.00

TOTAL 402 =	25,602,031.49
GL TOTAL (2)	25,602,031.49
DIFFERENCE	0.00

401 = 1,421,239.11

A/C 930.01 INCLUDED IN THIS ACCOUNT

401 = 29,904,740.09

A/C 935.06 INCLUDED IN THIS ACCOUNT

(2) Oracle GL665A FERC Trial Balance Report

Line #	FACTORS	2007			2007			FUNCTIONALIZATION			Page 4 of 6	Line #
		PEAK (4)	BASE (4)		100.00%			(1) 2006 ACTUAL COSS, FUNCTIONALIZATION RUN.	(4) ENTER ONLY 2 DECIMAL PLACES.			
1	BASE/PEAK SPLIT	33.13%	68.87%		100.00%			See Footnote 5 on C-1 for Explanation of why does not match 2006 COSS				1
2	JANUARY 2007 ACTUAL (1)	28.11%	71.89%		100.00%			(2) C-1, PAGE 1 OF 3 (Year is correct -- see description on C-1)				2
3	JANUARY 2008 ACTUAL (2)							(3) SAME FORMULAS AS PRIOR YEARS' FUNCTIONALIZATION RUNS				3
4												4
5												5
6												6
7												7
8												8
9												9
10												10
11	BEGINNING BALANCES											11
12	LAND	992,449	0		21,690,284	0						12
13	STATION EQUIPMENT	42,694,696	11,674,237		7,670,227	2,882,047						13
14	POLES, TOWERS & FIXTURES	27,318,310	11,674,237		7,670,227	2,882,047						14
15	OVERHEAD CONDUCTORS & DEVICES	16,277,880	11,674,237		7,670,227	2,882,047						15
16	UNDERGROUND CONDUIT	2,588	117		27,556,236	474						16
17	UNDERGROUND CONDUCTORS & DEVICES	11,596,921	522,004		27,556,236	474						17
18	LINE TRANSFORMERS	0	25,053,540		0	0						18
19	SERVICES	3,345,458	9,562,282		0	0						19
20	UNDERGROUND SERVICES	0	0		16,775,988	0						20
21	METERS	0	0		562,912	0						21
22	LOAD MANAGEMENT SWITCHES	0	0		2,382	0						22
23	INSTALLATION ON CUSTOMERS' PREMISES	0	0		0	0						23
24	ALL OTHER PRIVATE LIGHTING	0	0		0	0						24
25	STREETLIGHTING & SIGNAL SYSTEMS	0	0		0	0						25
26	TOTAL BEGINNING BALANCES	98,883,044	50,157,638		56,925,279	11,761,738						26
27												27
28	ENDING BALANCES											28
29	LAND	960,534	0		22,469,400	0						29
30	STATION EQUIPMENT	45,034,903	11,839,244		7,778,640	2,985,378						30
31	POLES, TOWERS & FIXTURES	28,299,586	11,839,244		7,778,640	2,985,378						31
32	OVERHEAD CONDUCTORS & DEVICES	16,507,956	11,839,244		7,778,640	2,985,378						32
33	UNDERGROUND CONDUIT	2,588	117		6,150	474						33
34	UNDERGROUND CONDUCTORS & DEVICES	12,252,677	551,522		29,114,422	2,242,778						34
35	LINE TRANSFORMERS	0	27,144,368		0	0						35
36	SERVICES	0	3,448,472		0	0						36
37	UNDERGROUND SERVICES	0	10,042,495		0	0						37
38	METERS	0	0		591,169	0						38
39	LOAD MANAGEMENT SWITCHES	0	0		2,382	0						39
40	INSTALLATION ON CUSTOMERS' PREMISES	0	0		0	0						40
41	ALL OTHER PRIVATE LIGHTING	0	0		0	0						41
42	STREETLIGHTING & SIGNAL SYSTEMS	0	0		0	0						42
43	TOTAL ENDING BALANCES	103,058,244	53,026,216		59,370,995	12,216,669						43
44												44
45												45
46												46
47	DISTRIBUTION EXPENSES											47
48	OPERATION, SUPERVISION & ENGINEERING	73,478	42,262		84,062	7,761						48
49	STATION EXPENSES	3,440	23,461		52,321	5,058						49
50	LINE EXPENSES	145,436	87,611		62,454	11,950						50
51	UNDERGROUND LINE EXPENSES	92,516	147,180		404,561	31,165						51
52	STREETLIGHTING & SIGNAL SYSTEM	170,258	147,180		404,561	31,165						52
53	METER EXPENSES	0	0		0	0						53
54	MISCELLANEOUS DISTRIBUTION EXPENSES	319,690	183,876		327,862	1,000,585						54
55	RENTS	126,121	100,138		584,448	783,605						55
56	MAINTENANCE, SUPERVISION & ENGINEERING	324,188	86,104		180,033	3,226						56
57	MAINTENANCE OF STATION EQUIPMENT	832,021	650,328		77,081	142,778						57
58	MAINTENANCE OF OVERHEAD LINES	1,906,078	111,015		1,286,728	246,212						58
59	MAINTENANCE OF UNDERGROUND LINES	128,422	0		305,153	23,507						59
60	MAINTENANCE OF LINE TRANSFORMERS	0	0		0	2,612						60
61	MAINTENANCE OF STREETLIGHTING & SIGNAL	0	0		0	992,747						61
62	MAINTENANCE OF METERS	0	0		0	441,438						62
63	MAINTENANCE OF PROPERTY IN AC 371	0	0		0	0						63
64												64
65	TOTAL DISTRIBUTION EXPENSES	4,157,949	1,331,858		2,841,193	1,508,249						65
66												66
67												67
68												68
69												69
70												70
71	LABOR RATIOS: 2006 (1)	37.42%	14.92%		23.51%	6.27%						71
72	LABOR RATIOS: 2007 (2)	36.81%	14.09%		25.04%	6.16%						72

(1) 2006 ACTUAL COSS FUNCTIONALIZATION RUN
(2) C-2, PAGE 1 OF 2

Line #			SYSTEM BALANCES		Line #
			12/31/06 (1)	12/31/07	
1	PLANT IN SERVICE				1
2	PRODUCTION PLANT				2
3	A/C 101 & 106 - BASE DEMAND		239,873,255	314,844,448	3
4	PEAK DEMAND		118,842,544	123,108,602	4
5	BASE ENERGY		0	0	5
6	SUBTOTAL A/C 101 & 106		358,715,800	437,953,050	6
7					7
8	A/C 114 - BASE DEMAND		1,062,066	1,141,796	8
9	PEAK DEMAND		526,189	446,458	9
10	BASE ENERGY		0	0	10
11					11
12	SUBTOTAL A/C 114		1,588,255	1,588,255	12
13					13
14	TOTAL PRODUCTION PLANT		360,304,054	439,541,305	14
15					15
16	TRANSMISSION PLANT				16
17	A/C 101 & 106		189,626,692	191,578,729	17
18	A/C 114		58,287	58,287	18
19					19
20	TOTAL TRANSMISSION PLANT		189,684,980	191,637,016	20
21					21
22	DISTRIBUTION PLANT - A/C 101, 106 & 114				22
23	PRIM DEM-INC A/C 114		98,883,044	103,058,244	23
24	SECONDARY DEMAND		50,157,638	53,026,216	24
25	PRIMARY CUSTOMER		58,925,279	59,370,995	25
26	SECONDARY CUSTOMER		58,152,203	61,692,818	26
27	STREET LIGHTING		11,761,736	12,216,669	27
28	AREA LIGHTING		4,406,276	4,547,052	28
29	METERS		19,437,773	19,758,102	29
30	LOAD MANAGEMENT		8,069,040	8,736,815	30
31					31
32	TOTAL DISTRIBUTION PLANT		307,792,988	322,405,912	32
33					33
34	GENERAL PLANT				34
35	PRODUCTION		25,954,032	26,164,716	35
36	TRANSMISSION		10,346,321	10,015,236	36
37	DISTRIBUTION		16,306,234	17,796,565	37
38	CUSTOMER ACCOUNTS		14,448,522	14,448,522	38
39	CUSTOMER SERVICE & INFO		4,349,792	4,378,556	39
40	LOAD MANAGEMENT		135,027	135,027	40
41					41
42	TOTAL GENERAL PLANT		69,493,744	71,215,483	42
43					43
44					44
45					45
46					46
47					47
48	OPERATING EXPENSES			AMOUNT	48
49	PRODUCTION EXPENSES				49
50	PROD EXPENSES EXCL PURCHASED POWER				50
51	BASE DEMAND			11,325,547	51
52	PEAK DEMAND			5,611,117	52
53	BASE ENERGY			62,473,643	53
54	PEAK ENERGY			6,236,150	54
55					55
56	TOTAL EXCLUDING PURCHASED POWER			85,646,457	56
57					57
58	TRANSMISSION EXPENSES			10,492,992	58
59					59
60	DISTRIBUTION EXPENSES				60
61	PRIMARY DEMAND			4,157,949	61
62	SECONDARY DEMAND			1,331,858	62
63	PRIMARY CUSTOMER			2,841,193	63
64	SECONDARY CUSTOMER			2,296,330	64
65	STREET LIGHTING			1,508,249	65
66	AREA LIGHTING			42,974	66
67	METERS			2,505,796	67
68	LOAD MANAGEMENT			0	68
69					69
70	TOTAL DISTRIBUTION			14,686,349	70

Line #				AMOUNT	2007	FUNCTIONALIZATION	Page 6 of 6	Line #
1	CUSTOMER ACCOUNTING EXPENSES							1
2	METER READING			4,654,956				2
3	OTHER			5,852,304				3
4								4
5	TOTAL CUSTOMER ACCOUNTS			10,507,260				5
6								6
7	CUSTOMER SERV & INFO EXP - MN			2,618,980				7
8	- ND			0				8
9	- SD			0				9
10	- OTHER			2,622,720				10
11								11
12	TOTAL CUSTOMER SERV & INFORMATION EXP			5,241,699				12
13								13
14	SALES EXPENSES - MN			0				14
15	- ND			427,508				15
16	- SD			0				16
17	- OTHER			993,731				17
18								18
19	TOTAL SALES EXPENSES			1,421,239				19
20								20
21	ADMINISTRATIVE & GENERAL EXPENSES							21
22	SALARIES, SUPPLIES, PENSIONS & BENEFITS							22
23	PRODUCTION			8,158,582				23
24	TRANSMISSION			3,122,913				24
25	DISTRIBUTION			5,549,875				25
26	CUSTOMER ACCOUNTS			3,967,362				26
27	CUSTOMER SERVICE & INFO			1,365,305				27
28								28
29	TOTAL A&G SALARIES, SUPPLIES, PENSIONS & BENEFITS			22,164,036				29
30								30
31	ADMINISTRATIVE & GENERAL EXPENSES							31
32	LOAD MANAGEMENT			0				32
33	OUTSIDE SERVICES (AC 923)			1,595,302				33
34	PROPERTY INSURANCE (AC 924)			974,518				34
35	INJURIES & DAMAGES (AC 925)			1,646,497				35
36								36
37	GENERAL ADVERTISING (AC 930.1)			615,095				37
38	MISC. RENTS, MAINTENANCE			3,702,507				38

Total Expenses Pgs 5 & 6 158,693,951.33
 Total Expenses Pgs 2 & 3 160,625,722.62
 Difference (1,931,771.29)
 Less: Regulatory Commission Expense 1,931,771.29 (1)
 (0.06) Rounding due to Distribution Allocation Factors

(1) Regulatory Commission Expense is included in Operating Expense above and then is pulled out down below as it is treated as a separate adjustment on the Input Summary.

Volume 4A – Section 1

2007 Test Year work papers

Input Summary

OTTER TAIL POWER COMPANY
SUMMARY OF AVERAGE RATE BASE
ACTUAL YEAR 2007 W/TEST YEAR CHANGES

(A) SYSTEM BALANCES				(C)		(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
Line	12/31/2006	12/31/2007	AVERAGE	EMISSION ALLOWANCES	ECONOMIC DEVELOPMENT	ADVERTISING EXPENSES	Non-Asset Wholesale Expenses	WIND PROJECT COSTS	DEF TAX BIG STONE DEF OH					TEST YEAR ADJUSTMENTS	TOTAL	Line
1	(1)	(3)						(5)								1
2																2
3	230,873,255	314,844,448	277,358,851					(23,732,362)						11,691,550	265,318,040	3
4	118,842,544	123,108,602	120,975,573					(9,279,687)						4,571,560	116,267,447	4
5	0	0	0											0	0	5
6																6
7	398,715,800	437,953,050	398,334,425	0	0		0	(33,012,048)	0					16,263,110	381,585,487	7
8																8
9	1,062,066	1,141,796	1,101,931											0	1,101,931	9
10	526,189	446,458	486,324											0	486,324	10
11	0	0	0											0	0	11
12														0	0	12
13	1,588,255	1,588,255	1,588,255	0	0		0		0					0	1,588,255	13
14														0	0	14
15	360,304,054	439,541,305	399,922,680	0	0		0	(33,012,048)	0					16,263,110	383,173,741	15
16																16
17	189,626,692	191,578,729	190,602,711											12,631,999	203,234,610	17
18	58,287	58,287	58,287											0	58,287	18
19	189,684,980	191,637,016	190,660,998	0	0		0		0					12,631,999	203,292,997	19
20																20
21																21
22																22
23																23
24	98,883,044	103,058,244	100,970,644											0	100,970,644	24
25	50,157,638	53,026,216	51,591,927											0	51,591,927	25
26	56,925,279	59,370,995	58,148,137											0	58,148,137	26
27	61,692,818	61,692,818	59,922,510											0	59,922,510	27
28	11,761,736	12,216,669	11,989,203											0	11,989,203	28
29	4,406,276	4,547,052	4,476,664											0	4,476,664	29
30	19,437,773	19,758,102	19,597,938											0	19,597,938	30
31	8,069,040	8,736,815	8,402,928											0	9,069,489	31
32														666,561		32
33	307,792,988	322,406,912	315,099,950	0	0		0		0					666,561	315,766,511	33
34																34
35																35
36	25,954,032	26,164,716	26,059,374											570,641	26,630,015	36
37	10,348,321	10,015,236	10,181,778											218,428	10,400,206	37
38	16,306,234	17,798,546	17,052,390											388,178	17,440,568	38
39	12,401,339	12,723,402	12,562,370											277,492	12,839,862	39
40	4,348,792	4,378,556	4,363,674											95,494	4,459,168	40
41	135,027	135,027	135,027											0	135,027	41
42																42
43	69,493,744	71,215,483	70,354,613	0	0		0		0					1,550,233	71,904,846	43
44																44
45	3,383,281	4,086,760	3,735,021											388,106	4,123,127	45
46																46
47	930,659,047	1,028,887,476	979,773,261	0	0		0	(33,012,048)	0					31,499,909	978,261,122	47
48																48
															978,261,122	check

(5) ND-4, Page 1 of 2

- (1) Functionalization run page 5 of 6 12/31/2006
(2) Financial Statement, p 10 12/31/2007
(3) Functionalization run page 5 of 6 12/31/2007
(4) Financial Statement, p 10, Total EPIS minus PHFU

1,028,917,132 29,656 1,028,887,476
Difference 0

OTTER TAIL POWER COMPANY
SUMMARY OF AVERAGE RATE BASE
ACTUAL YEAR 2007

(A) SYSTEM BALANCES				(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
Line	12/31/2006	12/31/2007	AVERAGE	EMISSION ALLOWANCES	ECONOMIC DEVELOPMENT	ADVERTISING EXPENSES	Non-Asset Wholesale Expenses	WIND PROJECT COSTS	DEF TAX BIG STONE DEF OH				TEST YEAR ADJUSTMENTS	TOTAL	Line
1	(1)	(1)	0												1
2			0												2
3			9,038											0	3
4			20,618											9,038	4
5			0											20,618	5
6			0											0	6
7			0											0	7
8			0											0	8
9	29,656	29,656	29,656	0	0	0	0	0	0	0	0	0	0	29,656	9
10	(2)	(2)	0											0	10
11			0											0	11
12			0											0	12
13			0											0	13
14			0											0	14
15			0											0	15
16			0											0	16
17	(3)	(3)	0											0	17
18			0											0	18
19			0											0	19
20			0											0	20
21			0											0	21
22			0											0	22
23			0											0	23
24			0											0	24
25			0											0	25
26			0											0	26
27	102,789	187,176	144,982											144,982	27
28	469,870	679,730	574,800											574,800	28
29	4,591,244	1,813,549	3,202,396											3,202,396	29
30	1,800,919	807,580	1,304,249											1,304,249	30
31			0											0	31
32			0											0	32
33	6,964,821	3,488,034	5,226,428	0	0	0	0	0	0	0	0	0	0	5,226,428	33
34			0											0	34
35			0											0	35
36	8,116,945	18,278,877	13,197,961											11,352,188	36
37	973,307	6,512,077	3,742,682										(1,845,673)	2,446,437	37
38	1,323,875	4,083,407	2,703,641										(1,296,255)	2,479,691	38
39	1,006,426	1,328,054	1,167,240										(223,750)	842,291	39
40			0										(324,949)	(301,460)	40
41			0										(301,460)	(301,460)	41
42	11,420,453	30,202,415	20,811,434	0	0	0	0	0	0	0	0	0	(3,992,087)	16,819,347	42
43			0											0	43
44	18,385,274	33,690,449	26,037,862	0	0	0	0	0	0	0	0	0	(3,992,087)	22,045,775	44
45			0											0	45
46			0											0	46
47			0											0	47
48			3,772,973											3,772,973	48
49			3,598,449											3,598,449	49
50			6,127,090											6,127,090	50
51			0											0	51
52			13,498,511	0	0	0	0	0	0	0	0	0	0	13,498,511	52
53			0											0	53
54			0											0	54
55			5,708,035											5,708,035	55
56			1,930,934											1,930,934	56
57			0											0	57
58			7,638,969	0	0	0	0	0	0	0	0	0	0	7,638,969	58
59			0											0	59
60	Av of 12 Av Mo Balances		(35,518,043)										3,991,701	(31,526,342)	60
(31,526,342) check															

(1) FINANCIAL STATEMENTS, PAGE 10
(2) B-11, PAGE 1 OF 1
(3) A-2, PAGE 1 OF 5
(4) A-3, PAGE 2 OF 3
(5) A-3, PAGE 1 OF 3
(6) A-8, PAGE 1 OF 1
(7) A-4, PAGE 1 OF 4

OTTER TAIL POWER COMPANY
OPERATING SUMMARY
ACTUAL YEAR 2007

NORTH DAKOTA

B-SUMMARY
PAGE 1 OF 7

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
		AMOUNT	EMISSION ALLOWANCES (5)	ECONOMIC DEVELOPMENT	ADVERTISING EXPENSES	Non-Asset Wholesale Expenses	WIND PROJECT COSTS	DEF TAX BIG STONE DEF OH			TEST YEAR ADJUSTMENTS	TOTAL
OPERATING REVENUES												
1		(1)										Line
2		134,836,006										1
3		108,472,410										2
4		25,388,754										3
5		0										4
6												5
7		268,698,170	0	0	0	0	0	0	0	0	9,822,791	6
8												7
9		(2)										8
10												9
11												10
12		190,431										11
13		21,001										12
14												13
15												14
16												15
17												16
18		0										17
19		0										18
20		20,133,608										19
21		0										20
22		0										21
23		20,345,040	0	0	0	0	0	0	0	0	609,734	22
24												23
25		(3)										24
26		294,443										25
27		170,779										26
28		80,104										27
29		190,817										28
30		89,754										29
31		35,174										30
32		644,002										31
33		(20,657)										32
34		11,846										33
35		2,589,668	129,650									34
36		3,651,858										35
37												36
38		34,025										37
39		207,155										38
40		216,350										39
41		9,518										40
42		4,459,926										41
43												42
44		66,381										43
45		9,642										44
46		872										45
47												46
48		12,741,656	129,650	0	0	0	0	0	0	0	451,503	47
49												48
50		33,086,696	129,650	0	0	0	0	0	0	0	1,061,237	49
51												50
52		301,784,866	129,650	0	0	0	0	0	0	0	10,884,028	51
TOTAL OPERATING REVENUES (4)												52
												check

(4) F/S, Elec Op Revenue =
Provision for Customer Refunds 309,903,774
Meter Error Adj 1,297,930
Plus interest on loan pools 0
Less COE accrual (1,450...) 76,895
MN Schedule 16 & 17 Ref RecVble (8,717,024)
ND Schedule 16 & 17 Ref RecVble (407,010)
Wheeling adjustment (from B-3) (369,698)
301,784,867

(1) B-1, PAGE 1 OF 2
(2) B-2, PAGE 1 OF 1
(3) B-3, PAGE 1 OF 5

(5) B-3, PAGE 1 OF 5, treated as non-operating gain on F/S adjustment reclassifies from credit to production expense to other misc revenue

OTTER TAIL POWER COMPANY
OPERATING SUMMARY
ACTUAL YEAR 2007

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
		AMOUNT	EMISSION ALLOWANCES (6)	ECONOMIC DEVELOPMENT	ADVERTISING EXPENSES	Non-Asset Wholesale Expenses (4)	WIND PROJECT COSTS	DEF TAX BIG STONE DEF OH			TEST YEAR ADJUSTMENTS	TOTAL
Line												
1		(1)										1
2		11,325,547									1,701,337	2
3		5,611,117				(\$1,117,324)					842,960	3
4		62,473,643				(\$553,623)					1,411,060	4
5		6,236,150									0	5
6											0	6
7											0	7
8											0	8
9		85,646,457	0	0	0	(1,670,957)	0	0	0	0	3,955,357	9
10												10
11		(2)										11
12												12
13		3,963,752										13
14		0										14
15		72,263,300	129,650								379,950	15
16		0									0	16
17		0									739,701	17
18											0	18
19		76,227,052	129,650	0	0	0		0	0	0	1,119,651	19
20												20
21		76,227,052	129,650	0	0	0		0	0	0	1,119,651	21
22												22
23		161,873,509	129,650	0	0	(1,670,957)		0	0	0	5,075,008	23
24		(1)										24
25		10,492,992				0					334,339	25
26												26
27		4,157,949									168,165	27
28		1,331,858									53,866	28
29		2,841,193									1,385,723	29
30		2,298,330									114,910	30
31		1,508,249									92,955	31
32		42,974									61,001	32
33		2,505,796									1,739	33
34		0									101,345	34
35											0	35
36		14,686,349	0	0	0	0		0	0	0	593,982	36
37												37
38												38
39		4,654,956									188,128	39
40		5,852,304									236,517	40
41												41
42		10,507,260	0	0	0	0		0	0	0	424,645	42
43												43
44		2,618,980										44
45		0				0					73,048	45
46		0									1,000,000	46
47		2,622,720									73,153	47
48												48
49												49
50		5,241,699	0	0	0	0		0	0	0	1,146,201	50
											11,46,201	
											6,387,900	
											check	

- (1) Not Used
(2) Adjustment removes credit to account 555 on the FERC F/S and moves it to a revenue credit B summary p 1 of 7 line 35
(3) Not Used
(4) Adjustment removes credit to account 555 on the FERC F/S and moves it to a revenue credit B summary p 1 of 7 line 35
- (1) FUNCTIONALIZATION RUNS
(2) B-4, PAGE 1 OF 5
(3) not used
(4) B-15 Page 1 of 6
- 12/31/2007

OTTER TAIL POWER COMPANY
OPERATING SUMMARY
ACTUAL YEAR 2007

NORTH DAKOTA

B-SUMMARY
PAGE 4 OF 7

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
		AMOUNT	EMISSION ALLOWANCES	ECONOMIC DEVELOPMENT	ADVERTISING EXPENSES	Non-Asset Wholesale Expenses	WIND PROJECT COSTS	DEF TAX BIG STONE DEF OH			TEST YEAR ADJUSTMENTS	TOTAL
Line												
1		(1)					(5)					1
2		3,534,759									282,554	2
3		2,549,090									345,916	3
4		567,254									0	4
5		6,962									54,057	5
6		1,382,467									188,940	6
7		996,966									0	7
8		221,857									0	8
9		2,723									0	9
10		0									0	10
11		0									0	11
12		0									0	12
13		0									0	13
14		0									0	14
15		9,262,078	0	0	0	0	0	0	0	0	871,467	15
16											0	16
17		(2)									(121,438)	17
18		2,048,582									86,362	18
19		1,527,896									0	19
20		328,726									0	20
21		42,536									0	21
22											0	22
23		3,947,740	0	0	0	0	0	0	0	0	(35,076)	23
24											0	24
25		3,985,561									(38,765)	25
26		3,918,044									(78,709)	26
27		850,943									0	27
28		21,444									0	28
29											0	29
30		8,775,992	0	0	0	0	0	0	0	0	(117,474)	30
31											0	31
32		1,212,572									(107,945)	32
33		1,002,568									(56,375)	33
34		218,332									0	34
35		6,309									0	35
36											0	36
37		2,439,781	0	0	0	0	0	0	0	0	(164,320)	37
38											0	38
39		410,801									155,242	39
40											0	40
41		24,836,391	0	0	0	0	0	0	0	0	709,839	41
											25,546,230	check

(5) ND-4, Page 2 of 2

(1) B-7, PAGE 1 OF 2
(2) B-7, PAGE 2 OF 2

(4) FERC F/S, p. 5 =
24,836,391

Difference from above
0

OTTER TAIL POWER COMPANY
OPERATING SUMMARY
ACTUAL YEAR 2007

NORTH DAKOTA

B-SUMMARY
PAGE 6 OF 7

Line	(A)	(B)	(C) AMOUNT	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M) TOTAL	Line
1			2,701,294										2,701,294	1
2		(6)	3,949,203										3,949,203	2
3		(6)												3
4														4
5		(2)	(26,138)										(26,138)	5
6		(2)	(59,233)										(59,233)	6
7		(2)	(7,848)										(7,848)	7
8		(2)	(67)										(67)	8
9		(1)	87,932										87,932	9
10		(7)	4,671,807										4,671,807	10
11		(7)	(8,598,414)										(8,598,414)	11
12		(1)											0	12
13		(6)	160,775										160,775	13
14		(3)	(1,606,800)										(1,606,800)	14
15		(6)											0	15
16		(4)	(4,946,621)										(4,946,621)	16
17		(4)											0	17
18		(3)	940,583										940,583	18
19		(4)	(18,508)										(18,508)	19
20		(4)											0	20
21		(4)											0	21
22		(3)	(9,000)										(9,000)	22
23		(5)	35,000%										35,000%	23
24		(5)	9.8%										9.8%	24
25		(5)	6.5%										6.5%	25
26		(5)	1,705,611										1,705,611	26
27		(5)	1,645,413										1,645,413	27
28		(5)	1,540,773										1,540,773	28
29		(5)	1,639,344										1,639,344	29

- (1) B-12, PAGE 1 OF 9
(2) B-12, PAGE 7 OF 9
(3) B-12, PAGE 6 OF 9
(4) B-12, PAGE 8 OF 9
(5) C-4, PAGE 1 OF 2
(6) B-12, PAGE 2 OF 9
(7) B-12, PAGE 4 OF 9

Schedule 16 & 17 Revenue Increase												
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
SALES OF ELECTRICITY		BY CLASS	W/O UNBILLED*	UNBILLED % BY CLASS	Unbilled	Revenue Adjustment						
(5)	36,574,921	RESIDENTIAL	70,103	33.497%	31,254							
(5)	1,590,979	FARMS	3,075	1.470%	(3,142)							
(5)	34,012,150	GENERAL SERVICE	65,276	31.191%	78,440							
(5)	36,231,788	LARGE GENERAL SERVICE	51,775	24.740%	212,540							
(5)	45,963	IRRIGATION	88	0.042%	(102)							
(5)	2,095,668	OUTDOOR LIGHTING	4,043	1.932%	(88)							
(5)	967,569	OPA	1,859	0.888%	(3,805)							
(5)	1,185,332	CONTROLLED WATER HEATING	2,276	1.087%	(3,254)							
(5)	4,744,402	CONTROLLED SERVICE INTERRUPT	9,157	4.376%	(1,975)							
(5)	849,617	CONTROLLED SERVICE DEFERRED	1,626	0.777%	(73)							
TOTAL			117,145,371	100.000%	208,279	0	309,796	0		644,731		
* Amounts are customer classes; Stat Book uses revenue classes.												
FACTORS		TOTAL	MN	ND	SD	FERC	CLASS TOTAL	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE	
(1)	D1	622,316	305,946	259,222	56,356	792	259,222	84,247	4,340	78,761	80,289	
(1)	D2	628,307	305,946	259,222	56,356	6,783	259,222	84,247	4,340	78,761	80,289	
(1)	D3	761,059	335,193	335,193	78,710	6,267	335,193	83,181	6,402	90,040	69,378	
(1)	D4	999,305	432,667	459,669	106,969	0	459,669	111,594	12,711	124,762	61,432	
(1)	E1	4,082,438	2,074,148	1,621,989	382,540	3,761	1,621,989	432,402	24,607	448,292	655,998	
(1)	E2	4,595,203	2,277,133	1,884,859	429,450	3,761	1,884,859	490,575	25,529	451,012	655,998	
(1)	C1	128,675	60,947	57,014	11,714	0	57,014	44,201	916	10,870	123	
(1)	C2	138,857	63,559	59,913	12,361	4	59,913	46,011	1,091	11,860	140	
(1)	C3	135,784	63,511	59,901	12,372	0	59,901	46,011	1,091	11,876	132	
(1)	C4	4,185,546	1,980,427	1,760,035	445,084	0	1,760,035	0	0	0	0	
(1)	C5	3,688,552	1,621,835	1,716,671	350,046	0	1,716,671	0	0	0	0	
(1)	C6	29,240,646	13,664,904	12,850,789	2,724,953	0	12,850,789	4,439,962	328,536	3,681,789	180,785	
(1)	C7	173,474	84,014	73,215	16,245	0	73,215	45,597	943	18,374	305	
(1)	C8	135,879	63,581	59,913	12,381	4	59,913	46,011	1,091	11,880	140	
(1)	C9	40,923	18,775	18,040	4,108	0	18,040	3,722	42	38	0	
		IRRIGATION	OUTDOOR LIGHTING	OPA	WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED					
(1)	D1	0	2,305	2,963	368	5,377	572					
(1)	D2	0	2,305	2,963	368	5,377	572					
(1)	D3	1,096	6,007	2,797	10,010	58,300	7,982					
(1)	D4	1,550	5,774	3,821	30,451	95,058	12,516					
(1)	E1	0	24,702	18,381	8,940	0	8,667					
(1)	E2	712	24,702	18,381	21,459	175,691	20,800					
(1)	C1	27	26	545	45	36	36					
(1)	C2	69	33	572	18	85	14					
(1)	C3	69	33	572	18	85	14					
(1)	C4	0	1,760,035	0	0	0	0					
(1)	C5	0	1,716,671	0	0	0	0					
(1)	C6	51,098	10,464	159,285	1,908,048	1,848,130	242,692					
(1)	C7	37	30	624	3,790	3,130	385					
(1)	C8	69	33	572	7,564	85	14					
(1)	C9	19	0	0	0	6,036	619					
		185,725,713										
(2)	LONG TERM AND SHORT TERM DEBT - AMOUNT											
(3)	PREFERRED STOCK - AMOUNT											
(4)	COMMON EQUITY - AMOUNT											
(2)	LONG TERM DEBT - RATE											
(3)	PREFERRED STOCK - RATE											
(6)	COMMON EQUITY - RATE											
(4) D-3												
(5) B-1, Pages 1 & 2 and report from Dean Hjelte												
(6) Requested												
		(3) D-2										

NORTH DAKOTA

OTTER TAIL POWER COMPANY
SUMMARY OF AVERAGE RATE BASE ADJUSTMENTS
TEST YEAR 2007

Line	(A) Normalized Plant-in-Service	(B) Post Retirement Benefit Obligation	(C) Depreciation Direct Assign vs Allocated	(D) Amortized Rate Case Expenses	(E) Employee Benefits Medical/Dental	(F) FAS 112 Postemployment Benefits	(G) FAS 106 Postemployment Benefits	(H) FASB 87 Pension Costs	(I) Corporate Allocations	(J) Depreciation Exp to Reflect 2008 Rates	(K) Depreciation Exp to Reflect 2009 Rates
1											
2											
3											
4	11,691,550										
5	4,571,560										
6											
7											
8	16,263,110	0	0	0	0	0	0	0	0	0	0
9											
10											
11											
12											
13	0	0	0	0	0	0	0	0	0	0	0
14											
15											
16	16,263,110	0	0	0	0	0	0	0	0	0	0
17											
18											
19	12,631,899										
20											
21											
22	12,631,899	0	0	0	0	0	0	0	0	0	0
23											
24											
25											
26											
27											
28											
29											
30											
31	666,561										
32											
33											
34	666,561	0	0	0	0	0	0	0	0	0	0
35											
36											
37	570,641										
38	218,428										
39	388,178										
40	277,492										
41	95,494										
42											
43											
44	1,550,233	0	0	0	0	0	0	0	0	0	0
45											
46	388,106										
47											
48	31,499,909	0	0	0	0	0	0	0	0	0	0

(A) 2007 ND TY-01

OTTER TAIL POWER COMPANY
SUMMARY OF AVERAGE RATE BASE ADJUSTMENTS
TEST YEAR 2007

Line	(L) Economic Development Costs	(M) Column Not Used	(N) Adjustment Due to Load Increase	(O) Revenue Adjustment Due to Billing Change	(P) Labor Expense - April & November Annual Increases	(Q) KPA & Utility Management Incentive	(R) Amortized Holding Company Expenses	(S) Column Not Used	(T) Property Ins/ Storm Repair Adjustment	(U) Column Not Used	(V) Column Not Used
1											
2											
3											
4											
5											
6											
7											
8	0	0	0	0	0	0	0	0	0	0	0
9											
10											
11											
12											
13	0	0	0	0	0	0	0	0	0	0	0
14											
15											
16	0	0	0	0	0	0	0	0	0	0	0
17											
18											
19											
20											
21											
22	0	0	0	0	0	0	0	0	0	0	0
23											
24											
25											
26											
27											
28											
29											
30											
31											
32											
33											
34	0	0	0	0	0	0	0	0	0	0	0
35											
36											
37											
38											
39											
40											
41											
42											
43											
44	0	0	0	0	0	0	0	0	0	0	0
45											
46											
47											
48	0	0	0	0	0	0	0	0	0	0	0

OTTER TAIL POWER COMPANY
SUMMARY OF AVERAGE RATE BASE ADJUSTMENTS
TEST YEAR 2007

A-SUMMARY

	(V)	(X)	(Y)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)
Line	Wholesale Margins Asset Based Revenue & Expense	Wholesale Margins Non-Asset Based Expense	CIP Adjustment	Charitable Contributions	Big Stone Outage Adjustment	Inter-Year Billing Adjustments	Amortization of Deferred MISO Sched 16 & 17	MISO Sched 16 & 17	Total Test Year Adjustments
1									
2									
3									
4									11,691,550
5									4,571,560
6									0
7									
8	0	0	0	0	0	0	0	0	16,263,110
9									
10									0
11									0
12									0
13									
14	0	0	0	0	0	0	0	0	0
15									
16	0	0	0	0	0	0	0	0	16,263,110
17									
18									
19									12,631,899
20									0
21									
22	0	0	0	0	0	0	0	0	12,631,899
23									
24									0
25									0
26									0
27									0
28									0
29									0
30									0
31									0
32									666,561
33									
34	0	0	0	0	0	0	0	0	666,561
35									
36									
37									570,641
38									218,428
39									388,178
40									277,492
41									95,494
42									0
43									
44	0	0	0	0	0	0	0	0	1,550,233
45									
46									388,106
47									
48	0	0	0	0	0	0	0	0	31,499,909
49									
50									
51									
52									
53									
54									
55									
56									
57									
58									
59									
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97									
98									
99									
100									

31,499,909 check

OTTER TAIL POWER COMPANY
SUMMARY OF AVERAGE RATE BASE ADJUSTMENTS
TEST YEAR 2007

[illegible]

(A) 2007 ND TY-01

(C) 2007 ND TY-03

(J) 2007 ND TY-07 (K) 2007 ND TY-08

OTTER TAIL POWER COMPANY
SUMMARY OF AVERAGE RATE BASE ADJUSTMENTS
TEST YEAR 2007

Line	(L) Economic Development Costs	(M) Column Not Used	(N) Adjustment Due to Load Increase	(O) Revenue Adjustment Due to Billing Change	(P) Labor Expense - April & November Annual Increases	(Q) KPA & Utility Management Incentive	(R) Amortized Holding Company Expenses	(S) Column Not Used	(T) Property Ins/ Storm Repair Adjustment	(U) Column Not Used	(V) Column Not Used
1											
2											
3											
4											
5											
6											
7											
8											
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13											
14											
15											
16											
17											
18	0	0	0	0	0	0	0	0	0	0	0
19											
20											
21											
22											
23											
24											
25	0	0	0	0	0	0	0	0	0	0	0
26											
27											
28											
29											
30											
31											
32	0	0	0	0	0	0	0	0	0	0	0
33											
34											
35											
36											
37											
38											
39	0	0	0	0	0	0	0	0	0	0	0
40											
41											
42											
43	0	0	0	0	0	0	0	0	0	0	0
44											
45											
46											
47											
48											
49											
50											
51	0	0	0	0	0	0	0	0	0	0	0
52											
53											
54	0	0	0	0	0	0	0	0	0	0	0
55											
56											
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100											

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OTTER TAIL POWER COMPANY
SUMMARY OF AVERAGE RATE BASE ADJUSTMENTS
TEST YEAR 2007

A-SUMMARY

Line	(V) Wholseate Margins Asset Based Revenue & Expense	(X) Wholseate Margins Non-Asset Based Expense	(Y) CIP Adjustment	(Z) Charitable Contributions	(AA) Big Stone Outage Adjustment	(AB) Inter-Year Billing Adjustments	(AC) Amortization of Deferred MISO Sched 16 & 17	(AD) MISO Sched 16 & 17	(AE) Total Test Year Adjustments	Line
1										1
2										2
3										3
4										4
5									1,765,317	5
6									31,235	6
7									(2,517,468)	7
8									89,219	8
9									2,217,118	9
10									(1,380,889)	10
11									(1,095,436)	11
12									14,948	12
13									0	13
14									0	14
15									0	15
16									0	16
17									0	17
18	0	0	0	0	0	0	0	0	(875,956)	18
19										19
20									1,761,074	20
21									(806,059)	21
22									(860,977)	22
23									(58,962)	23
24										24
25	0	0	0	0	0	0	0	0	35,076	25
26										26
27									(257,276)	27
28									937,081	28
29									(616,781)	29
30									30,658	30
31										31
32	0	0	0	0	0	0	0	0	93,682	32
33										33
34									325,891	34
35									(64,252)	35
36									(93,169)	36
37									(4,150)	37
38										38
39	0	0	0	0	0	0	0	0	164,320	39
40										40
41									(155,242)	41
42	0	0	0	0	0	0	0	0	(738,120)	42
43										43
44										44
45									0	45
46									0	46
47									0	47
48									0	48
49									0	49
50									0	50
51	0	0	0	0	0	0	0	0	0	51
52										52
53										53
54	0	0	0	0	0	0	0	0	30,761,789	54
TOTAL NET PLANT IN SERVICE										

30,761,789 check
0

OTTER TAIL POWER COMPANY
SUMMARY OF AVERAGE RATE BASE ADJUSTMENTS
TEST YEAR 2007

Line	(A) Normalized Plant-in-Service	(B) Post Retirement Benefit Obligation	(C) Depreciation Direct Assign vs Allocated	(D) Amortized Rate Case Expenses	(E) Employee Benefits Medical/Dental	(F) FAS 112 Postemployment Benefits	(G) FAS 106 Postemployment Benefits	(H) FASB 87 Pension Costs	(I) Corporate Allocations	(J) Depreciation Exp to Reflect 2008 Rates	(K) Depreciation Exp to Reflect 2009 Rates
1											
2											
3											
4											
5											
6											
7											
8											
9	0	0	0	0	0	0	0	0	0	0	0
10											
11											
12											
13											
14											
15											
16	0	0	0	0	0	0	0	0	0	0	0
17											
18											
19											
20											
21											
22											
23											
24											
25	0	0	0	0	0	0	0	0	0	0	0
26											
27											
28											
29											
30											
31											
32											
33											
34	0	0	0	0	0	0	0	0	0	0	0
35											
36											
37	(1,845,673)										
38	(1,286,255)										
39	(223,750)										
40	(324,949)										
41	(301,460)										
42											
43	(3,992,087)	0	0	0	0	0	0	0	0	0	0
44											
45	(3,992,087)	0	0	0	0	0	0	0	0	0	0
46											
47											
48											
49											
50											
51											
52	0	0	0	0	0	0	0	0	0	0	0
53											
54											
55											
56											
57											
58	0	0	0	0	0	0	0	0	0	0	0
59		3,991,701									
60											

(A) 2007 ND TY-01 (B) 2007 ND TY-02

OTTER TAIL POWER COMPANY
SUMMARY OF AVERAGE RATE BASE ADJUSTMENTS
TEST YEAR 2007

Line	(L) Economic Development Costs	(M) Column Not Used	(N) Adjustment Due to Load Increase	(O) Revenue Adjustment Due to Billing Change	(P) Labor Expense - April & November Annual Increases	(Q) KPA & Utility Management Incentive	(R) Amortized Holding Company Expenses	(S) Column Not Used	(T) Property Ins/ Storm Repair Adjustment	(U) Column Not Used	(V) Column Not Used
1											
2											
3											
4											
5											
6											
7											
8											
9	0	0		0	0	0	0	0	0	0	0
10											
11											
12											
13											
14											
15											
16	0	0		0	0	0	0	0	0	0	0
17											
18											
19											
20											
21											
22											
23											
24											
25	0	0		0	0	0	0	0	0	0	0
26											
27											
28											
29											
30											
31											
32											
33											
34	0	0		0	0	0	0	0	0	0	0
35											
36											
37											
38											
39											
40											
41											
42											
43	0	0		0	0	0	0	0	0	0	0
44											
45	0	0		0	0	0	0	0	0	0	0
46											
47											
48											
49											
50											
51											
52	0	0		0	0	0	0	0	0	0	0
53											
54											
55											
56											
57											
58	0	0		0	0	0	0	0	0	0	0
59											
60											

OTTER TAIL POWER COMPANY
SUMMARY OF AVERAGE RATE BASE ADJUSTMENTS
TEST YEAR 2007

[illegible]

OTTER TAIL POWER COMPANY
SUMMARY OF AVERAGE RATE BASE ADJUSTMENTS
TEST YEAR 2007

	Line	(L) Economic Development Costs	(M) Column Not Used	(N) Adjustment Due to Load Increase	(O) Revenue Adjustment Due to Billing Change	(P) Labor Expense - April & November Annual Increases	(Q) KPA & Utility Management Incentive	(R) Amortized Holding Company Expenses	(S) Column Not Used	(T) Property Ins/ Storm Repair Adjustment	(U) Column Not Used	(V) Column Not Used
ACCUMULATED DEFERRED INCOME TAXES	1											
	2											
	3											
	4											
	5											
	6											
	7											
	8	0	0		0	0		0	0	0	0	0
	9											
	10											
ALL OTHER FEDERAL MINNESOTA NORTH DAKOTA	11											
	12											
	13											
	14											
	15	0	0		0	0		0	0	0	0	0
	16											
	17											
	18											
	19											
	20											
UNAMORTIZED RATE CASE EXPENSES	21											
	22											
	23											
	24											
	25	0	0		0	0		0	0	0	0	0
TOTAL	26											
	27											
	28											
	29											
CUSTOMER ADVANCES (& DEPOSITS)	30	0	0	0	0	0		0	0	0	0	0
TOTAL AVERAGE RATE BASE												

OTTER TAIL POWER COMPANY
SUMMARY OF AVERAGE RATE BASE ADJUSTMENTS
TEST YEAR 2007

A-SUMMARY

Line	(W) Wholesale Margins Asset Based Revenue & Expense	(X) Wholesale Margins Non-Asset Based Expense	(Y) CIP Adjustment	(Z) Charitable Contributions	(AA) Big Stone Outage Adjustment	(AB) Inter-Year Billing Adjustments	(AC) Amortization of Deferred MISO Sched 16 & 17	(AD) MISO Sched 16 & 17	(AE) Total Test Year Adjustments	Line
1										1
2										2
3										3
4										4
5										5
6										6
7										7
8	0	0	0	0	0	0	0	0	0	8
9										9
10										10
11										11
12										12
13										13
14										14
15	0	0	0	0	0	0	0	0	0	15
16										16
17										17
18										18
19										19
20										20
21										21
22										22
23										23
24										24
25	0	0	0	0	0	0	0	0	0	25
26										26
27										27
28										28
29										29
30	0	0	0	0	0	0	0	0	30,761,403	30

30,761,403 check

**OTTER TAIL POWER COMPANY
OPERATING SUMMARY ADJUSTMENTS
TEST YEAR 2007**

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OTTER TAIL POWER COMPANY
OPERATING SUMMARY ADJUSTMENTS
TEST YEAR 2007

Line	(L) Economic Development Costs	(M) Column Not Used	(N) Adjustment Due to Load Increase	(O) Revenue Adjustment Due to Billing Change	(P) Labor Expense - April & November Annual Increases	(Q) KPA & Utility Management Incentive	(R) Amortized Holding Company Expenses	(S) Column Not Used	(T) Property Ins/ Storm Repair Adjustment	(U) Column Not Used	(V) Column Not Used
1											
2											
3			8,882,240								
4											
5											
6											
7	0	0	8,882,240	0	0	0	0	0	0	0	0
8											
9											
10											
11											
12											
13											
14											
15											
16											
17											
18											
19											
20											
21											
22											
23	0	0	0	0	0	0	0	0	0	0	0
24											
25											
26											
27											
28											
29											
30											
31											
32											
33											
34											
35				451,503							
36											
37											
38											
39											
40											
41											
42											
43											
44											
45											
46											
47											
48	0	0	0	451,503	0	0	0	0	0	0	0
49											
50	0	0	0	451,503	0	0	0	0	0	0	0
51											
52	0	0	8,882,240	451,503	0	0	0	0	0	0	0

(P) 2007 ND TY-10 (P) 2007 ND TY-11

OTTER TAIL POWER COMPANY
OPERATING SUMMARY ADJUSTMENTS
TEST YEAR 2007

	(A) Normalized Plant-in-Service	(B) Post Retirement Benefit Obligation	(C) Depreciation Direct Assign vs Allocated	(D) Amortized Rate Case Expenses	(E) Employee Benefits Medical/Dental	(F) FAS 112 Postemployment Benefits	(G) FAS 106 Postemployment Benefits	(H) FASB 87 Pension Costs	(I) Corporate Allocations	(J) Depreciation Exp to Reflect 2008 Rates	(K) Depreciation Exp to Reflect 2009 Rates
Line	1										
1											
2											
3											
4											
5					207,525	12,337	48,977	(226,859)			
6					102,816	6,112	24,265	(112,395)			
7											
8											
9	0	0	0	0	310,341	18,449	73,242	(339,254)	0	0	0
10											
11											
12											
13											
14											
15											
16											
17											
18											
19	0	0	0	0	0	0	0	0	0	0	0
20											
21	0	0	0	0	0	0	0	0	0	0	0
22											
23	0	0	0	0	310,341	18,449	73,242	(339,254)	0	0	0
24											
25					118,807	7,063	28,039	(129,876)			
26											
27											
28					59,758	3,552	14,103	(65,325)			
29					19,141	1,138	4,517	(20,925)			
30					40,833	2,427	9,637	(44,638)			
31					33,031	1,964	7,796	(36,109)			
32					21,676	1,289	5,116	(23,696)			
33					618	37	146	(675)			
34					36,013	2,141	8,499	(39,368)			
35											
36											
37	0	0	0	0	211,071	12,548	49,814	(230,735)	0	0	0
38											
39											
40					66,851	3,974	15,777	(73,079)			
41					84,047	4,996	19,835	(91,877)			
42											
43	0	0	0	0	150,898	8,970	35,612	(164,956)	0	0	0
44											
45					25,958	1,543	6,126	(28,376)			
46											
47					25,995	1,545	6,135	(28,417)			
48											
49											
50	0	0	0	0	51,953	3,088	12,261	(56,793)	0	0	0

**OTTER TAIL POWER COMPANY
OPERATING SUMMARY ADJUSTMENTS
TEST YEAR 2007**

	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)
Line	Economic Development Costs	Column Not Used	Adjustment Due to Load Increase	Revenue Adjustment Due to Billing Change	Labor Expense - April & November Annual Increases	KPA & Utility Management Incentive	Amortized Holding Company Expenses	Column Not Used	Property Ins/ Storm Repair Adjustment	Column Not Used	Column Not Used
OPERATING EXPENSES											
PRODUCTION EXPENSES											
PROD EXPENSES EXCL PURCHASED POWER											
BASE DEMAND					530,409	11,613					
PEAK DEMAND					262,785	5,754					
BASE ENERGY											
PEAK ENERGY											
TOTAL EXCLUDING PURCHASED POWER	0	0	0	0	793,195	17,367	0	0	0	0	0
PURCHASED POWER											
BASE DEMAND			379,950								
PEAK DEMAND											
BASE ENERGY			6,956,559								
PEAK ENERGY											
TOTAL ALL OTHER TRANSACTIONS	0	0	7,336,509	0	0	0	0	0	0	0	0
TOTAL PURCHASED POWER	0	0	7,336,509	0	0	0	0	0	0	0	0
TOTAL PRODUCTION EXPENSES	0	0	7,336,509	0	793,195	17,367	0	0	0	0	0
TRANSMISSION EXPENSES											0
PRIMARY DEMAND					303,657	6,648					0
SECONDARY DEMAND					152,734	3,344					0
PRIMARY CUSTOMER					48,923	1,071					0
SECONDARY CUSTOMER					104,365	2,285					0
STREETLIGHTING					84,424	1,848					0
AREA LIGHTING					55,402	1,213					0
METERS					1,579	35					0
LOAD MANAGEMENT					92,045	2,015					0
TOTAL DISTRIBUTION	0	0	0	0	539,472	11,812	0	0	0	0	0
CUSTOMER ACCOUNTING EXPENSES											
METER READING					170,864	3,741					
OTHER					214,813	4,703					
TOTAL CUSTOMER ACCOUNTS	0	0	0	0	385,677	8,444	0	0	0	0	0
CUSTOMER SERV & INFO EXP - (MN CIP)					66,345	1,453					
- ND											
- SD					66,440	1,455					
- OTHER											
TOTAL CUSTOMER SERV & INFORMATION EXP	0	0	0	0	132,785	2,907	0	0	0	0	0

(P) 2007 ND TY-10

(P) 2007 ND TY-12 (Q) 2007 ND TY-12

OTTER TAIL POWER COMPANY
OPERATING SUMMARY ADJUSTMENTS
TEST YEAR 2007

B-SUMMARY

Line	(W) Wholesale Margins Asset Based Revenue & Expense	(X) Wholesale Margins Non-Asset Based Expense	(Y) CIP Adjustment	(Z) Charitable Contributions	(AA) Big Stone Outage Adjustment	(AB) Inter-Year Billing Adjustments	(AC) Amortization of Deferred MISO Sched 16 & 17	(AD) MISO Sched 16 & 17	(AE) Total Test Year Adjustments	
1										1
2										2
3										3
4										4
5										5
6										6
7										7
8										8
9										9
10										10
11										11
12										12
13										13
14										14
15										15
16										16
17										17
18										18
19										19
20										20
21										21
22										22
23										23
24										24
25										25
26										26
27										27
28										28
29										29
30										30
31										31
32										32
33										33
34										34
35										35
36										36
37										37
38										38
39										39
40										40
41										41
42										42
43										43
44										44
45										45
46										46
47										47
48										48
49										49
50										50
OPERATING EXPENSES										
PRODUCTION EXPENSES										
PROD EXPENSES EXCL PURCHASED POWER										
BASE DEMAND										
PEAK DEMAND										
BASE ENERGY										
PEAK ENERGY										
TOTAL EXCLUDING PURCHASED POWER										
PURCHASED POWER										
BASE DEMAND										
PEAK DEMAND										
BASE ENERGY										
PEAK ENERGY										
TOTAL ALL OTHER TRANSACTIONS										
TOTAL PURCHASED POWER										
TOTAL PRODUCTION EXPENSES										
TRANSMISSION EXPENSES										
DISTRIBUTION EXPENSES										
PRIMARY DEMAND										
SECONDARY DEMAND										
PRIMARY CUSTOMER										
SECONDARY CUSTOMER										
STREETLIGHTING										
AREA LIGHTING										
METERS										
LOAD MANAGEMENT										
TOTAL DISTRIBUTION										
CUSTOMER ACCOUNTING EXPENSES										
METER READING										
OTHER										
TOTAL CUSTOMER ACCOUNTS										
CUSTOMER SERV & INFO EXP - (MN CIP)										
- ND										
- SD										
- OTHER										
TOTAL CUSTOMER SERV & INFORMATION EXP										

1,146,201 check

(W) 2007 ND TY-15 (X) 2007 ND TY-16 (Y) 2007 ND TY-17 (AA) 2007 ND TY-19 (AC) 2007 ND TY-21 (AD) 2007 ND TY-21

OTTER TAIL POWER COMPANY
OPERATING SUMMARY ADJUSTMENTS
TEST YEAR 2007

Line	(A) Normalized Plant-in-Service	(B) Post Retirement Benefit Obligation	(C) Depreciation Direct Assign vs Allocated	(D) Amortized Rate Case Expenses	(E) Employee Benefits Medical/Dental	(F) FAS 112 Postemployment Benefits	(G) FAS 106 Postemployment Benefits	(H) FASB 87 Pension Costs	(I) Corporate Allocations	(J) Depreciation Exp to Reflect 2008 Rates	(K) Depreciation Exp to Reflect 2009 Rates
1											
2											
3											
4											
5											
6											
7	0	0	0	0	0	0	0	0	0	0	0
8											
9											
10											
11					150,172	8,927	35,441	(164,163)	(36,574)		
12					57,482	3,417	13,566	(62,838)	(13,999)		
13					102,155	6,073	24,109	(111,672)	(24,879)		
14					73,026	4,341	17,234	(79,829)	(17,786)		
15					25,131	1,494	5,931	(27,472)	(6,120)		
16					407,966	24,252	96,282	(445,974)	(99,358)		
17	0	0	0	0						0	0
18											
19											
20											
21											
22											
23											
24											
25				166,667							
26											
27											
28											
29											
30	0	0	0	166,667	0	0	0	0	0	0	0
31											
32											
33											
34	0	0	0	166,667	407,966	24,252	96,282	(445,974)	(99,358)	0	0
35											
36											
37											
38											
39											
40											
41	0	0	0	0	0	0	0	0	0	0	0
42											
43				166,667	1,251,037	74,370	295,250	(1,367,587)	(99,358)	0	0
44	0	0	0								

(D) 2007 ND TY-04 (E) 2007 ND TY-05 (F) 2007 ND TY-05 (G) 2007 ND TY-05 (H) 2007 ND TY-05 (J) 2007 ND TY-06

OTTER TAIL POWER COMPANY
OPERATING SUMMARY ADJUSTMENTS
TEST YEAR 2007

Line	(L) Economic Development Costs	(M) Column Not Used	(N) Adjustment Due to Load Increase	(O) Revenue Adjustment Due to Billing Change	(P) Labor Expense - April & November Annual Increases	(Q) KPA & Utility Management Incentive	(R) Amortized Holding Company Expenses	(S) Column Not Used	(T) Property Ins/ Storm Repair Adjustment	(U) Column Not Used	(V) Column Not Used
ADMINISTRATIVE & GENERAL EXPENSES - (CONTINUED)											
SALES EXPENSES - MN											
1											
2	72,492										
3											
4											
5											
6											
7	72,492	0	0	0	0	0	0	0	0	0	0
TOTAL SALES EXPENSES											
8											
ADMINISTRATIVE & GENERAL EXPENSES											
SALARIES, SUPPLIES, PENSIONS & BENEFITS											
9											
10											
11					390,183	37,202					
12					155,573	14,833					
13					245,142	23,373					
14					186,437	17,776					
15					65,378	6,233					
16											
17	0	0	0	0	1,042,712	99,418	0	0	0	0	0
TOTAL A&G SALARIES, SUPP, PENSIONS & BENEFITS											
18											
ADMINISTRATIVE & GENERAL EXPENSES											
19											
20							131,708		285,354		
21											
22											
23											
24											
25											
26											
27											
28											
29											
30	0	0	0	0	0	0	0	0	0	0	0
TOTAL REGULATORY COMMISSION EXPENSE											
31											
32											
33											
34	0	0	0	0	1,042,712	99,418	131,708	0	285,354	0	0
TOTAL ADMINISTRATIVE & GENERAL EXPENSE											
35											
CHARITABLE CONTRIBUTIONS (& CUST DEP INTEREST)											
36											
37											
38											
39											
40											
41	0	0	0	0	0	0	0	0	0	0	0
42											
43											
44	72,492	0	7,336,509	0	3,197,498	146,596	131,708	0	285,354	0	0
TOTAL O & M EXPENSES											

(L) 2007 ND TY-09

(P) 2007 ND TY-12 (Q) 2007 ND TY-12 (R) 2007 ND TY-13

(T) 2007 ND TY-14

OTTER TAIL POWER COMPANY
OPERATING SUMMARY ADJUSTMENTS
TEST YEAR 2007

B-SUMMARY

		(V)	(X)	(Y)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	Line
		Wholesale Margins Asset Based Revenue & Expense	Wholesale Margins Non-Asset Based Expense	C/P Adjustment	Charitable Contributions	Big Stone Outage Adjustment	Inter-Year Billing Adjustments	Amortization of Deferred MISO Sched 16 & 17	MISO Sched 16 & 17	Total Test Year Adjustments	
ADMINISTRATIVE & GENERAL EXPENSES - (CONTINUED)	1									0	1
SALES EXPENSES - MN	2									72,492	2
- ND	3									0	3
- SD	4									0	4
- OTHER	5									0	5
	6									0	6
TOTAL SALES EXPENSES	7	0	0	0	0	0	0	0	0	72,492	7
	8										8
ADMINISTRATIVE & GENERAL EXPENSES	9										9
SALARIES, SUPPLIES, PENSIONS & BENEFITS	10										10
PRODUCTION	11		48							421,237	11
TRANSMISSION	12		18							168,053	12
DISTRIBUTION	13		32							264,333	13
CUSTOMER ACCOUNTS	14		23							201,222	14
CUSTOMER SERVICE & INFO	15		8							70,583	15
	16										16
TOTAL A&G SALARIES, SUPP, PENSIONS & BENEFITS	17	0	129	0	0	0	0	0	0	1,125,428	17
	18										18
ADMINISTRATIVE & GENERAL EXPENSES	19										19
LOAD MANAGEMENT	20									0	20
OUTSIDE SERVICES (A/C 923)	21									131,708	21
PROPERTY INSURANCE (A/C 924)	22									285,354	22
INJURIES & DAMAGES (A/C 925)	23									0	23
	24									0	24
REGULATORY COMM EXP (A/C 928)-MN	25									0	25
-ND	26									166,667	26
-SD	27									0	27
-FERC	28									0	28
	29										29
TOTAL REGULATORY COMMISSION EXPENSE	30	0	0	0	0	0	0	0	0	166,667	30
GENERAL ADVERTISING (A/C 930.1)	31									0	31
MISC. RENTS, MAINTENANCE	32									0	32
	33										33
TOTAL ADMINISTRATIVE & GENERAL EXPENSE	34	0	129	0	0	0	0	0	0	1,709,157	34
	35										35
CHARITABLE CONTRIBUTIONS (& CUST DEP INTEREST)	36										36
MINNESOTA ONLY	37									0	37
NORTH DAKOTA ONLY	38				114,816					114,816	38
SOUTH DAKOTA ONLY	39									0	39
	40										40
TOTAL CHARITABLE CONTRIBUTIONS (& CUST DEP INT)	41	0	0	0	114,816	0	0	0	0	114,816	41
	42										42
	43										43
TOTAL O & M EXPENSES	44	1,411,060	1,671,087	1,000,000	114,816	(7,596,764)	0	753,376	626,530	9,470,640	44

9,470,640 check

(Z) 2007 ND TY-18

(X) 2007 ND TY-16

OTTER TAIL POWER COMPANY
OPERATING SUMMARY ADJUSTMENTS
TEST YEAR 2007

Line	(A) Normalized Plant-in-Service	(B) Post Retirement Benefit Obligation	(C) Depreciation Direct Assign vs Allocated	(D) Amortized Rate Case Expenses	(E) Employee Benefits Medical/Dental	(F) FAS 112 Postemployment Benefits	(G) FAS 106 Postemployment Benefits	(H) FASE 87 Pension Costs	(I) Corporate Allocations	(J) Depreciation Exp to Reflect 2008 Rates	(K) Depreciation Exp to Reflect 2009 Rates
1											
2											
3	282,248		(96,219)							78,824	17,701
4	186,065		96,219							51,963	11,669
5											
6											
7	106,841		(87,722)							1,532	33,406
8	76,276		87,722							1,093	23,849
9											
10											
11											
12											
13											
14											
15											
16	651,430	0	0	0	0	0	0	0	0	133,412	86,625
17											
18	164,305		(100,834)							(30,355)	(154,554)
19	115,397		100,834							(21,320)	(108,549)
20											
21											
22											
23	279,702	0	0	0	0	0	0	0	0	(51,875)	(263,103)
24											
25	10,991		26,619							(21,649)	(54,726)
26	8,756		(26,619)							(17,247)	(49,599)
27											
28											
29											
30	19,747	0	0	0	0	0	0	0	0	(38,896)	(98,325)
31											
32	40,331		(10,709)							(3,470)	(134,097)
33	27,825		10,709							(2,394)	(92,515)
34											
35											
36											
37	68,156	0	0	0	0	0	0	0	0	(5,864)	(228,612)
38											
39	155,242										
40											
41	1,174,277	0	0	0	0	0	0	0	0	36,977	(501,415)

(A) 2007 ND TY-01

(C) 2007 ND TY-03

(J) 2007 ND TY-07 (K) 2007 ND TY-08

OTTER TAIL POWER COMPANY
OPERATING SUMMARY ADJUSTMENTS
TEST YEAR 2007

Line	(L) Economic Development Costs	(M) Column Not Used	(N) Adjustment Due to Load Increase	(O) Revenue Adjustment Due to Billing Change	(P) Labor Expense - April & November Annual Increases	(Q) KPA & Utility Management Incentive	(R) Amortized Holding Company Expenses	(S) Column Not Used	(T) Property Ins/ Storm Repair Adjustment	(U) Column Not Used	(V) Column Not Used
1		0	0	0	0	0	0	0	0	0	0
2											
3											
4											
5											
6											
7											
8											
9											
10											
11											
12											
13											
14											
15											
16		0	0	0	0	0	0	0	0	0	0
17											
18											
19											
20											
21											
22		0	0	0	0	0	0	0	0	0	0
23											
24											
25											
26											
27											
28											
29		0	0	0	0	0	0	0	0	0	0
30											
31											
32											
33											
34											
35											
36											
37	0	0	0	0	0	0	0	0	0	0	0
38											
39											
40		0	0	0	0	0	0	0	0	0	0
41											

OTTER TAIL POWER COMPANY
OPERATING SUMMARY ADJUSTMENTS
TEST YEAR 2007

B-SUMMARY

	(V)	(X)	(Y)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	Line
	Wholesale Margins Asset Based Revenue & Expense	Wholesale Margins Non-Asset Based Expense	CIP Adjustment	Charitable Contributions	Big Stone Outage Adjustment	Inter-Year Billing Adjustments	Amortization of Deferred MISO Sched 16 & 17	MISO Sched 16 & 17	Total Test Year Adjustments	
DEPRECIATION EXPENSE										1
PRODUCTION PLANT										2
BASE DEMAND - MN									282,554	3
- ND									345,916	4
- SD									0	5
- FERC									0	6
PEAK DEMAND - MN									54,057	7
- ND									186,940	8
- SD									0	9
- FERC									0	10
BASE ENERGY - MN									0	11
- ND									0	12
- SD									0	13
- FERC									0	14
TOTAL PRODUCTION PLANT	0	0	0	0	0	0	0	0	871,467	15
TRANSMISSION PLANT - MN										16
- ND									(121,438)	17
- SD									86,362	18
- FERC									0	19
TOTAL TRANSMISSION PLANT	0	0	0	0	0	0	0	0	(35,076)	20
DISTRIBUTION PLANT - MN										21
- ND										22
- SD										23
- FERC									(38,765)	24
TOTAL DISTRIBUTION PLANT	0	0	0	0	0	0	0	0	(78,709)	25
GENERAL PLANT - MN										26
- ND									0	27
- SD									0	28
- FERC									0	29
TOTAL GENERAL PLANT	0	0	0	0	0	0	0	0	(117,474)	30
INTANGIBLE PLANT										31
TOTAL DEPRECIATION EXPENSE	0	0	0	0	0	0	0	0	(107,945)	32
									(56,375)	33
									0	34
									0	35
									0	36
									(164,320)	37
										38
										39
									155,242	40
										41
	0	0	0	0	0	0	0	0	709,839	

709,839 check

OTTER TAIL POWER COMPANY
OPERATING SUMMARY ADJUSTMENTS
TEST YEAR 2007

NORTH DAKOTA

Line	(A) Normalized Plant-in-Service	(B) Post Retirement Benefit Obligation	(C) Depreciation Direct Assign vs Allocated	(D) Amortized Rate Case Expenses	(E) Employee Benefits Medical/Dental	(F) FAS 112 Postemployment Benefits	(G) FAS 106 Postemployment Benefits	(H) FASB 87 Pension Costs	(I) Corporate Allocations	(J) Depreciation Exp to Reflect 2008 Rates	(K) Depreciation Exp to Reflect 2009 Rates
1											
2											
3											
4											
5											
6											
7	0	0	0	0	0	0	0	0	0	0	0
8											
9											
10											
11											
12											
13											
14	0	0	0	0	0	0	0	0	0	0	0
15											
16											
17											
18	1,174,277	0	0	166,667	1,251,037	74,370	295,250	(1,367,587)	(99,358)	36,977	(501,415)
19											
20	(1,174,277)	0	0	(166,667)	(1,251,037)	(74,370)	(295,250)	1,367,587	99,358	(36,977)	501,415
21											
22											
23											
24											
25											
26	0	0	0	0	0	0	0	0	0	0	0
27											
28											
29											
30											
31											
32											
33											
34	0	0	0	0	0	0	0	0	0	0	0
35											
36											
37											
38											
39											
40	0	0	0	0	0	0	0	0	0	0	0
41											
42	0	0	0	0	0	0	0	0	0	0	0
43											
44											

ALLOWANCE FOR FUNDS USED DURING CONST

OTTER TAIL POWER COMPANY
OPERATING SUMMARY ADJUSTMENTS
TEST YEAR 2007

Line	(L) Economic Development Costs	(M) Column Not Used	(N) Adjustment Due to Load Increase	(O) Revenue Adjustment Due to Billing Change	(P) Labor Expense - April & November Annual Increases	(Q) KPA & Utility Management Incentive	(R) Amortized Holding Company Expenses	(S) Column Not Used	(T) Property Ins/ Storm Repair Adjustment	(U) Column Not Used	(V) Column Not Used
1											
2											
3											
4											
5											
6											
7	0	0	0	0	0	0	0	0	0	0	0
8											
9											
10											
11											
12											
13											
14	0	0	0	0	0	0	0	0	0	0	0
15											
16											
17											
18	72,492	0	7,336,509	0	3,197,498	146,596	131,708	0	285,354	0	0
19											
20	(72,492)	0	1,545,731	451,503	(3,197,498)	(146,596)	(131,708)	0	(285,354)	0	0
21											
22											
23											
24											
25											
26	0	0	0	0	0	0	0	0	0	0	0
27											
28											
29											
30											
31											
32											
33											
34	0	0	0	0	0	0	0	0	0	0	0
35											
36											
37											
38											
39											
40	0	0	0	0	0	0	0	0	0	0	0
41											
42	0	0	0	0	0	0	0	0	0	0	0
43											
44											

OTTER TAIL POWER COMPANY
OPERATING SUMMARY ADJUSTMENTS
TEST YEAR 2007

B-SUMMARY

Line	(V) Wholesale Margins Asset Based Revenue & Expense	(X) Wholesale Margins Non-Asset Based Expense	(Y) CIP Adjustment	(Z) Charitable Contributions	(AA) Big Stone Outage Adjustment	(AB) Inter-Year Billing Adjustments	(AC) Amortization of Deferred MISO Sched 16 & 17	(AD) MISO Sched 16 & 17	(AE) Total Test Year Adjustments	Line
1										1
2										2
3										3
4										4
5										5
6										6
7	0	0	0	0	0	0	0	0	0	7
8										8
9										9
10										10
11										11
12										12
13										13
14	0	0	0	0	0	0	0	0	0	14
15										15
16										16
17										17
18	1,411,060	1,671,087	1,000,000	114,816	(7,596,764)	0	753,376	626,530	10,180,479	18
19										19
20	(801,326)	(1,671,087)	(1,000,000)	(114,816)	7,596,764	295,819	(753,376)	18,201	703,549	20
21										21
22										22
23										23
24										24
25										25
26	0	0	0	0	0	0	0	0	0	26
27										27
28										28
29										29
30										30
31										31
32										32
33										33
34	0	0	0	0	0	0	0	0	0	34
35										35
36										36
37										37
38										38
39										39
40	0	0	0	0	0	0	0	0	0	40
41										41
42	0	0	0	0	0	0	0	0	0	42
43										43
44										44
10,180,479 check										
703,549 check										

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2007 Test Year work papers

Test Year Adjustments

North Dakota Test Year Adjustments

TY-01	Normalized Plant in Service
TY-02	Post Retirement Benefit Obligation
TY-03	Depreciation Direct Assign vs Allocated
TY-04	Amortized Rate Case Expenses
TY-05	Employee Benefits Medical/Dental
TY-05	FAS 112 Postemployment Benefits
TY-05	FAS 106 Postemployment Benefits
TY-05	FASB 87 Pension Costs
TY-06	Corporate Allocations
TY-07	Depreciation Expense to Reflect 2008 Rates
TY-08	Depreciation Expense to Reflect 2009 Rates
TY-09	Economic Development Costs
TY-10	Adjustment Due to Load Increase
TY-11	Revenue Adjustment Due to Billing Change
TY-12	Labor Expense - April & November Annual Increases
TY-12	KPA & Utility Management Incentive
TY-13	Amortized Holding Company Expenses
TY-14	Property Insurance/Storm Repair Adjustment
TY-15	Wholesale Margins Asset Based Revenue & Expense
TY-16	WholeSale Margins Non-Asset Based Revenue & Expense
TY-17	CIP Adjustment
TY-18	Charitable Contributions
TY-19	Big Stone Outage Adjustment
TY-20	Inter-Year Billing Adjustments
TY-21	Amortization of Deferred MISO Schedules 16 & 17
TY-21	MISO Schedules 16 & 17
TY-22	Impact of the change in allocation factors due to the addition of a large load in North Dakota

ADJUSTMENT TO ANNUALIZE DEPRECIATION AND OTHER OPERATING EXPENSE ON CURRENT AND FUTURE CAPITAL PROJECTS

	(A)	(B)	(C)	(D)	(E)
Line No.	Depreciation Expense	System-Wide	Allocation Factor	Allocation Percentage	ND Test-Year Amount
	Additions				PJB Schedule 8 Reference
1	Production				
2	Base Demand	468,313	E1	39.730897%	186,065
3	Peak Demand	183,117	D1	41.654420%	76,276
4	Total Production	<u>651,430</u>			<u>262,341</u>
5	Transmission	279,702	D2	41.257266%	115,397
6	Distribution	19,747	P60	44.341715%	8,756
7	General	68,156	P90	41.582448%	28,341
8	Intangible	<u>155,242</u>	P90	41.582448%	<u>64,553</u>
9	Total Depreciation Expense Additions	<u>1,174,277</u>			479,389 Col (I); Line 12
10	Income Tax Impact: ND Tax Rate is	39.23%			<u>188,040</u> Col (I); Line 19
11	Net Operating Income Impact				<u><u>291,349</u></u> Col (I); Line 23

ADJUSTMENT TO ANNUALIZE PLANT-IN-SERVICE ON CURRENT AND FUTURE CAPITAL PROJECTS

Line No.		(A)	(B)	(C)	(D)	(E)
	<u>Plant-in-Service</u>	<u>System-Wide</u>	<u>Allocation Factor</u>	<u>Allocation Percentage</u>	<u>ND Test-Year Amount</u>	<u>KAS Schedule 4 Reference</u>
	Additions					
1	Production					
2	Base Demand	11,691,550	E1	39.730897%	4,645,158	
3	Peak Demand	4,571,560	D1	41.654420%	1,904,257	
4	Total Production	<u>16,263,110</u>			<u>6,549,415</u>	Col (B); Line 1
5	Transmission	12,631,899	D2	41.257266%	5,211,576	Col (B); Line 2
6	Distribution - Load Mgmt	666,561	C9	44.082790%	293,839	Col (B); Line 3
7	General					
8	Production	570,641	P10	40.316998%	230,065	
9	Transmission	218,428	D2	41.257266%	90,117	
10	Distribution	388,178	P60	44.341715%	172,125	
11	Customer Acctg	277,492	OXC	43.256597%	120,033	
12	Customer Srvc	95,494	OXI	34.209830%	32,668	
13	Total General	<u>1,550,233</u>			<u>645,009</u>	Col (B); Line 4
14	Intangible	<u>388,106</u>	P90	41.582448%	<u>161,384</u>	Col (B); Line 5
15	Total Plant-in-Service Additions	<u><u>31,499,909</u></u>			<u><u>12,861,223</u></u>	Col (B); Line 6
	Accumulated Depreciation					
	Additions	<u>System-Wide</u>	<u>Allocation Factor</u>	<u>Allocation Percentage</u>	<u>ND Test-Year Amount</u>	
16	Production					
17	Base Demand	(471,540)	E1	39.730897%	(187,347)	
18	Peak Demand	(184,379)	D1	41.654420%	(76,802)	
19	Total Production	<u>(655,919)</u>			<u>(264,149)</u>	Col (B); Line 7
20	Transmission	(279,702)	D2	41.257266%	(115,397)	Col (B); Line 8
21	Distribution	(43,539)	P60	44.341715%	(19,306)	Col (B); Line 9
22	General	(68,156)	P90	41.582448%	(28,341)	Col (B); Line 10
23	Intangible	<u>(155,242)</u>	P90	41.582448%	<u>(64,553)</u>	Col (B); Line 11
24	Total A/D Additions	<u><u>(1,202,558)</u></u>			<u><u>(491,747)</u></u>	Col (B); Line 12
	L-T Construction Work-in-Progress					
	Transfers	<u>System-Wide</u>	<u>Allocation Factor</u>	<u>Allocation Percentage</u>	<u>ND Test-Year Amount</u>	
25	Production	(1,845,674)	P10	37.918130%	0	
26	Transmission	(1,296,255)	D2	39.150834%	0	
27	Distribution	(223,750)	P60	44.307890%	0	
28	General	(324,949)	P90	39.622959%	0	
29	Intangible	<u>(301,460)</u>	P90	39.622959%	<u>0</u>	
30	Total CWIP Transfers	<u><u>(3,992,087)</u></u>			<u><u>0</u></u>	Col (B); Line 22

Note: L-T CWIP is not allowed in the Rate Base calculation for ND.

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(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Projects Moved from CWIP @ 12/31/06 to Capitalized Accounts During 2007							
Line No.	Project	Project Description	Function	Amount in CWIP @ 12/31/06	Additional Charges Incurred During 2007	Total Project Costs	
1	102499	Load Mgmt Replacement	Distribution	447,499	885,624	1,333,123	
2	102879	PNAA	Intangible	602,919	173,292	776,212	
3	103405	BSP - Brine Concentrator	Production	463	756,712	757,176	
4	102747	Hoot Lake - VIC Site Work	Production	800,622	1,200	801,822	

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
Test Year Adjustment to CWIP to Transfer Project Costs to Capitalized Accounts								
Line No.	Project	Project Description	Function	Amount in CWIP @ 12/31/06	Amount in CWIP @ 12/31/07	Average Rate Base	2007 Test Year CWIP Adjustment	Input Cell
5	102499	Load Mgmt Replacement	Distribution	447,499	0	223,750	(223,750)	C199
6	102879	PNAA	Intangible	602,919	0	301,460	(301,460)	C201
7	103405	BSP - Brine Concentrator	Production	463	0	232	(232)	C197
8	102747	Hoot Lake - VIC Site Work	Production	800,622	0	400,311	(400,311)	C197
9				1,851,504	0	925,752	(925,753)	
10				Total 2007 Test Year Adjustment to CWIP			(925,753)	

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
Test Year Adjustment to Plant in Service to Transfer Project Costs to Capitalized Accounts								
Line No.	Project	Project Description	Function	Amount Capitalized @ 12/31/06	Amount Capitalized @ 12/31/07	Average Rate Base	2007 Test Year Plant-in-Service Adjustment	Input Cell
11	102499	Load Mgmt Replacement	Distribution	0	1,333,123	666,561	666,561	C43
12	102879	PNAA	Intangible	0	776,212	388,106	388,106	C57
13	103405	BSP - Brine Concentrator	Production	0	757,176	378,588	378,588	
14	102747	Hoot Lake - VIC Site Work	Production	0	801,822	400,911	400,911	
15		Base Demand - 71.89%		0	1,120,764	560,382	560,382	C15
16		Peak Demand - 28.11%		0	438,234	219,117	219,117	C16
17				0	3,668,332	1,834,166	1,834,166	
18				Total 2007 Test Year Adjustment to Plant in Service			1,834,166	

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(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Projects Moved from CWIP @ 12/31/07 to Capitalized Accounts During 2008							
Line No.	Project	Project Description	Function	Amount in CWIP @ 12/31/07	Additional Charges Incurred During 2008	Additional Charges Incurred Thru 10/31/09	Total Project Costs
1 x	103495	Hi-Tech Addition	General	649,897	900,336	0	1,550,233
2 x	103560	HL - #2 Burner Upgrade	Production	768,759	1,669,964	0	2,438,723
3 x	103371	HL - Superheater Tubes	Production	1,071,351	379,128	0	1,450,479
4 x	103228	Coyote - GSU	Production	955,200	1,653,841		2,609,041
5 x	103540 & 103615	Langdon Wind	Production	Recovered by Rider - Pulled out of COSS		0	N/A
6 x	103615	Hensel Substation	Transmission	402,359	1,988,022	0	2,390,381
7 x	74198 & 103317	Appleton/Canby	Transmission	1,859,496	370,713	810,009	3,040,218
8				5,707,062	6,962,004	810,009	13,479,075

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
Test Year Adjustment to CWIP to Transfer Project Costs to Capitalized Accounts								
Line No.	Project	Project Description	Function	Amount in CWIP @ 12/31/06	Amount in CWIP @ 12/31/07	Average Rate Base	2007 Test Year CWIP Adjustment	Input Cell
9 x	103495	Hi-Tech Addition	General	0	649,897	324,949	(324,949)	C200
10 x	103560	HL - #2 Burner Upgrade	Production	0	768,759	384,380	(384,380)	
11 x	103371	HL - Superheater Tubes	Production	94,950	1,071,351	583,151	(583,151)	
12 x	103228	Coyote - GSU	Production	0	955,200	477,600	(477,600)	
13 x	103540 & 103615	Langdon Wind	Production	0	Recovered by Rider - Pulled out of COSS		N/A	
14				94,950	2,795,310	1,445,130	(1,445,130)	C197
15 x	103615	Hensel Substation	Transmission	0	402,359	201,180	(201,180)	
16 x	74198 & 103317	Appleton/Canby	Transmission	330,654	1,859,496	1,095,075	(1,095,075)	
17				330,654	2,261,855	1,296,255	(1,296,255)	C198
18				425,604	5,707,062	3,066,333	(3,066,333)	
19				Total 2007 Test Year Adjustment to CWIP			(3,066,333)	

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)		
Test Year Adjustment to Plant in Service to Transfer Project Costs to Capitalized Accounts									
Line No.	Project	Project Description	Function	Amount Capitalized @ 12/31/07	Amount Capitalized During '08 or '09	Average Rate Base	2007 Test Year Plant-in-Service Adjustment	Input Cell	
20	x	103495	Hi-Tech Addition	General	0	1,550,233	775,117	1,550,233	
21			Production - 36.81%			570,641	285,320	570,641	C48
22			Transmission - 14.09%			218,428	109,214	218,428	C49
23			Distribution - 25.04%			388,178	194,089	388,178	C50
24			Customer Acctg - 17.90%			277,492	138,746	277,492	C51
25			Customer Svc - 6.16%			95,494	47,747	95,494	C52
26	x	103560	HL - #2 Burner Upgrade	Production	0	2,438,723	1,219,362	2,438,723	
27	x	103371	HL - Superheater Tubes	Production	0	1,450,479	725,240	1,450,479	
28	x	103228	Coyote - GSU	Production	0	2,609,041	1,304,521	2,609,041	
29	x	103540	Langdon Wind	Production	0	Recovered by Rider - Pulled out of COSS		0	
30			Base Demand - 71.89%	0	4,671,587	2,335,793	4,671,587	C15	
31			Peak Demand - 28.11%	0	1,826,656	913,328	1,826,656	C16	
32	x	103615	Hensel Substation	Transmission	0	2,390,381	1,195,191	2,390,381	
33	x	74198 & 103317	Appleton/Canby	Transmission	0	3,040,218	1,520,109	3,040,218	
34				0	5,430,599	2,715,300	5,430,599	C30	
35				0	13,479,075	6,739,538	13,479,075		
36				Total 2007 Test Year Adjustment to Plant in Service			13,479,075		

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(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)		
Test Year Adjustment to Accumulated Depreciation to Reflect Increase in Plant in Service									
Line No.	Project	Project Description	Function	Accumulated Depreciation @ 12/31/07	Accumulated Depreciation @ 12/31/08 or 10/31/09	Difference	2007 Test Year A/D Adjustment	Input Cell	
1	x	103495	Hi-Tech Addition	General	0	(68,156)	(68,156)	(68,156)	
2	x	103560	HL - #2 Burner Upgrade	Production	0	(87,477)	(87,477)	(87,477)	
3	x	103371	HL - Superheater Tubes	Production	0	(52,029)	(52,029)	(52,029)	
4	x	103228	Coyote - GSU	Production	0	(47,401)	(47,401)	(47,401)	
5	x	103540 & 103615	Langdon Wind	Production	0	Recovered by Rider - Pulled out of COSS	N/A		
6		Base Demand - 71.89%		0	(134,367)	(134,367)	(134,367)		
7		Peak Demand - 28.11%		0	(52,540)	(52,540)	(52,540)		
8	x	103615	Hensel Substation	Transmission	0	(51,831)	(51,831)	(51,831)	
9	x	74198 & 103317	Appleton/Canby	Transmission	0	(53,950)	(53,950)	(53,950)	
10				0	(105,781)	(105,781)	(105,781)		
11				0	(360,844)	(360,844)	(360,844)		
12				Total 2007 Test Year Adjustment to Accumulated Depreciation			(360,844)		
13		Function	System Amount	Allocation Factor	Allocation Percentage	ND Allocation	Other Allocation		
13		General	(68,156)	P90	41.582448%	(28,341)	(39,815)		C119, C118
14		Prod - Base Demand	(134,367)	E1	39.730897%	(53,385)	(80,982)		C90, C89
15		Prod - Peak Demand	(52,540)	D1	41.654420%	(21,885)	(30,655)		C94, C93
16		Transmission	(105,781)	D2	41.257266%	(43,642)	(62,139)		C105, C104
17						(147,254)	(213,590)		
18				Total System Adjustment			(360,844)		

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
Test Year Adjustment Depreciation Expense to Reflect Increase in Plant in Service								
Line No.	Project	Project Description	Function	Depreciation Expense 2007	Depreciation Expense 2008 or thru 10/31/09	Difference	2007 Test Year Expense Adjustment	Input Cell
19	x	103495	Hi-Tech Addition	General	0	68,156	68,156	68,156
20	x	103560	HL - #2 Burner Upgrade	Production	0	87,477	87,477	87,477
21	x	103371	HL - Superheater Tubes	Production	0	52,029	52,029	52,029
22	x	103228	Coyote - GSU	Production	0	47,401	47,401	47,401
23	x	103540 & 103615	Langdon Wind	Production	0	Recovered by Rider - Pulled out of COSS		0
24		Base Demand - 71.89%		0	134,367	134,367	134,367	
25		Peak Demand - 28.11%		0	52,540	52,540	52,540	
26	x	103615	Hensel Substation	Transmission	0	51,831	51,831	51,831
27	x	74198 & 103317	Appleton/Canby	Transmission	0	53,950	53,950	53,950
28				0	105,781	105,781	105,781	
29				0	360,844	360,844	360,844	
30				Total 2007 Test Year Adjustment to Depreciation Expense			360,844	
31		Function	System Amount	Allocation Factor	Allocation Percentage	ND Allocation	Other Allocation	
32		General	68,156	P90	41.582448%	28,341	39,815	C650, C649
33		Prod - Base Demand	134,367	E1	39.730897%	53,385	80,982	C621, C620
34		Prod - Peak Demand	52,540	D1	41.654420%	21,885	30,655	C625, C624
35		Transmission	105,781	D2	41.257266%	43,642	62,139	C636, C635
						147,254	213,590	
36				Total System Adjustment			360,844	

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Projects Started and Placed-in-Service During 2007								
Line No.	Project	Project Description	Function	Amount in CWIP @ 12/31/06	Additional Charges Incurred During 2007	Total Project Costs		
1	103401	BSP - Condenser Retube	Production	0	1,879,849	1,879,849		
2	103402	BSP - AHPC Replacement	Production	0	8,431,462	8,431,462		
3	103404	BSP - Generator Rewind	Production	0	4,659,425	4,659,425		
4	103540	Langdon Wind Farm	Production	Recovered by Rider - Pulled out of COSS	N/A	N/A		
5				0	14,970,735	14,970,735		

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Test Year Adjustment to CWIP to Transfer Project Costs to Capitalized Accounts								
Line No.	Project	Project Description	Function	Amount in CWIP @ 12/31/06	Amount in CWIP @ 12/31/07	Average Rate Base	2007 Test Year CWIP Adjustment	Input Cell
6	103401	BSP - Condenser Retube	Production	0	0	0	0	
7	103402	BSP - AHPC Replacement	Production	0	0	0	0	
8	103404	BSP - Generator Rewind	Production	0	0	0	0	
9	103540	Langdon Wind Farm	Production	0	Recovered by Rider - Pulled out of COSS		N/A	
10				0	0	0	0	
11				Total 2007 Test Year Adjustment to CWIP			0	N/A

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Test Year Adjustment to Plant in Service to Transfer Project Costs to Capitalized Accounts								
Line No.	Project	Project Description	Function	Amount Capitalized @ 12/31/06	Amount Capitalized @ 12/31/07	Average Rate Base	2007 Test Year Plant-in-Service Adjustment	Input Cell
12	103401	BSP - Condenser Retube	Production	0	1,879,849	939,924	939,924	
13	103402	BSP - AHPC Replacement	Production	0	8,431,462	4,215,731	4,215,731	
14	103404	BSP - Generator Rewind	Production	0	4,659,425	2,329,712	2,329,712	
15	103540	Langdon Wind Farm	Production	0	Recovered by Rider - Pulled out of COSS		N/A	
16		Base Demand - 71.89%		0	10,762,461	5,381,231	5,381,231	C15
17		Peak Demand - 28.11%		0	4,208,274	2,104,137	2,104,137	C16
18				Total 2007 Test Year Adjustment to Plant in Service			7,485,368	

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Test Year Adjustment to Accumulated Depreciation to Reflect Increase in Plant in Service								
Line No.	Project	Project Description	Function	Accumulated Depreciation @ 12/31/07	Accumulated Depreciation Using Exp for '08 or '09	Difference	2007 Test Year A/D Adjustment	Input Cell
19	103401	BSP - Condenser Retube	Production	0	(63,996)	(63,996)	(63,996)	
20	103402	BSP - AHPC Replacement	Production	(42,866)	(239,215)	(196,349)	(196,349)	
21	103404	BSP - Generator Rewind	Production	0	(158,621)	(158,621)	(158,621)	
22	103540	Langdon Wind	Production	0	Recovered by Rider - Pulled out of COSS		N/A	
23		Base Demand - 71.89%		(30,816)	(332,011)	(301,195)	(301,195)	
24		Peak Demand - 28.11%		(12,050)	(129,821)	(117,771)	(117,771)	
25				Total 2007 Test Year Adjustment to Accumulated Depreciation			(418,966)	
	Adjustment	Function	System Amount	Allocation Factor	Allocation Percentage	ND Allocation	Other Allocation	
26	Base Demand	Production	(301,195)	E1	39.730897%	(119,667)	(181,527)	C90, C89
27	Peak Demand	Production	(117,771)	D1	41.654420%	(49,057)	(68,714)	C94, C93
28						(168,724)	(250,242)	
29				Total System Adjustment			(418,966)	

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
Test Year Adjustment to Depreciation Expense to Reflect Increase in Plant in Service								
Line No.	Project	Project Description	Function	Depreciation Expense 2007	Depreciation Expense 2008 or thru 10/31/09	Difference	2007 Test Year Expense Adjustment	Input Cell
30	103401	BSP - Condenser Retube	Production	0	63,996	63,996	63,996	
31	103402	BSP - AHPC Replacement	Production	42,866	239,215	196,349	196,349	
32	103404	BSP - Generator Rewind	Production	0	158,621	158,621	158,621	
33	103540	Langdon Wind	Production	0	Recovered by Rider - Pulled out of COSS		N/A	
34		Base Demand - 71.89%		30,816	332,011	301,195	301,195	
35		Peak Demand - 28.11%		12,050	129,821	117,771	117,771	
36				Total 2007 Test Year Adjustment to Depreciation Expense			418,966	
37		Function	System Amount	Allocation Factor	Allocation Percentage	ND Allocation	Other Allocation	
38		Prod. - Base Demand	301,195	E1	39.730897%	119,667	181,527	C621, C620
39		Prod. - Peak Demand	117,771	D1	41.654420%	49,057	68,714	C625, C624
						168,724	250,242	
40				Total System Adjustment			418,966	

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(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Projects Started and Placed-in-Service During 2008							
Line No.	Project	Project Description	Function	Amount in CWIP @ 12/31/07	Additional Charges Incurred During 2008	Additional Charges Incurred Thru 10/31/09	Total Project Costs
1 x	103855	HL - Unit 3; Superheater Tubes	Production	0	300,000	1,200,000	1,500,000
2 x	103859	Laverne Wind Farm	Production	Recovered by Rider - Pulled out of COSS			N/A
3 x	103843	Ashtabula Wind Farm	Production	Recovered by Rider - Pulled out of COSS			N/A
4 x	103806	Casselton Ethanol Plant	Transmission	0	7,201,300		7,201,300
5				0	7,501,300	1,200,000	8,701,300

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
Test Year Adjustment to CWIP to Transfer Project Costs to Capitalized Accounts								
Line No.	Project	Project Description	Function	Amount in CWIP @ 12/31/06	Amount in CWIP @ 12/31/07	Average Rate Base	2007 Test Year CWIP Adjustment	Input Cell
6	x	103855	HL - Unit 3; Superheater Tubes	Production	0	0	0	
7	x	103859	Laverne Wind Farm	Production	0	Recovered by Rider - Pulled out of COSS	0	
8	x	103843	Ashtabula Wind Farm	Production	0	Recovered by Rider - Pulled out of COSS	0	
9				0	0	0	0	N/A
10	x	103806	Casselton Ethanol Plant	Transmission	0	0	0	
11				0	0	0	0	N/A
12				0	0	0	0	
13				Total 2007 Test Year Adjustment to CWIP			0	

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)		
Test Year Adjustment to Plant in Service to Transfer Project Costs to Capitalized Accounts									
Line No.	Project	Project Description	Function	Amount Capitalized @ 12/31/07	Amount Capitalized @ 12/31/08 or '09	Difference	2007 Test Year Plant-in-Service Adjustment	Input Cell	
14	x	103855	HL - Unit 3; Superheater Tubes	Production	0	1,500,000	1,500,000	1,500,000	
15	x	103859	Laverne Wind Farm	Production	0	Recovered by Rider - Pulled out of COSS	0		
16	x	103843	Ashtabula Wind Farm	Production	0	Recovered by Rider - Pulled out of COSS	0		
17		Base Demand - 71.89%		0	1,078,350	1,078,350	1,078,350		C15
18		Peak Demand - 28.11%		0	421,650	421,650	421,650		C16
19	x	103806	Casselton Ethanol Plant	Transmission	0	7,201,300	7,201,300	7,201,300	
20				0	7,201,300	7,201,300	7,201,300		C30
21				0	8,701,300	8,701,300	8,701,300		
22				Total 2007 Test Year Adjustment to Plant in Service			8,701,300		

Otter Tail Power Company
Capitalized Projects Adjustment
Adjustment Annualizes the Investment

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(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
Test Year Adjustment to Accumulated Depreciation to Reflect Increase in Plant in Service								
Line No.	Project	Project Description	Function	Accumulated Depreciation @ 12/31/07	Accumulated Depreciation @ 12/31/08 or '09	Difference	2007 Test Year A/D Adjustment	Input Cell
1	x	103855	HL - Unit 3; Superheater Tubes	Production	0	0	0	0
2	x	103859	Laverne Wind Farm	Production	0	Recovered by Rider - Pulled out of COSS		N/A
3	x	103843	Ashtabula Wind Farm	Production	0	Recovered by Rider - Pulled out of COSS		N/A
4			Base Demand - 71.89%	0	0	0	0	
5			Peak Demand - 28.11%	0	0	0	0	
6	x	103806	Casselton Ethanol Plant	Transmission	0	(173,921)	(173,921)	(173,921)
7				0	(173,921)	(173,921)	(173,921)	
8				0	(173,921)	(173,921)	(173,921)	
9				Total 2007 Test Year Adjustment to Accumulated Depreciation			(173,921)	
10		Function	System Amount	Allocation Factor	Allocation Percentage	ND Allocation	Other Allocation	
11		Prod. - Base Demand	0	E1	39.730897%	0	0	C90, C89
12		Prod. - Peak Demand	0	D1	41.654420%	0	0	C94, C93
13		Transmission	(173,921)	D2	41.257266%	(71,755)	(102,166)	C105, C104
14					Total System Adjustment		(173,921)	

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	
Test Year Adjustment to Depreciation Expense to Reflect Increase in Plant in Service								
Line No.	Project	Project Description	Function	Depreciation Expense 2007	Depreciation Expense 2008 or 2009	Difference	2007 Test Year Expense Adjustment	Input Cell
15	x	103855	HL - Unit 3; Superheater Tubes	Production	0	0	0	0
16	x	103859	Laverne Wind Farm	Production	0	Recovered by Rider - Pulled out of COSS	0	0
17	x	103843	Ashtabula Wind Farm	Production	0	Recovered by Rider - Pulled out of COSS	0	0
18		Base Demand - 71.89%		0	0	0	0	
19		Peak Demand - 28.11%		0	0	0	0	
20	x	103806	Casselton Ethanol Plant	Transmission	0	173,921	173,921	173,921
21				0	173,921	173,921	173,921	
22				0	173,921	173,921	173,921	
23				Total 2007 Test Year Adjustment to Depreciation Expense			173,921	
		Function	System Amount	Allocation Factor	Allocation Percentage	ND Allocation	Other Allocation	
24		Prod. - Base Demand	0	E1	39.730897%	0	0	C621, C620
25		Prod. - Peak Demand	0	D1	41.654420%	0	0	C625, C624
26		Transmission	173,921	D2	41.257266%	71,755	102,166	C636, C635
27						71,755	102,166	
28					Total System Adjustment		173,921	

ADJUSTMENT TO REVERSE FAS 158 ENTRY TO POST RETIREMENT BENEFITS

		(A)	(B)	(C)	(D)	(E)
Line No.	Description	Total Utility	Allocator	Allocator %	ND	KAS Schedule 4 Reference
1	2007 FAS 158 Adjustment to Prepayments	3,991,701	NEPIS	42.050142%	1,678,516	Col (C); Line 25

Adjustment to Reverse FAS 158 Entry

Otter Tail Power Company			
Post Retirement Benefits Other Than Pension			
Actual 12 Months Ending December 31, 2007			

Line No.	(A)	(B)	(C)	(D)
	Account 228.03/2440.3200 & 2440.3250			
	Month			Provision
1	December	End	2006	(32,254,146)
2	January	End	2007	(32,687,839)
3		Beg	2007	(32,687,839)
4	February	End	2007	(32,561,650)
5		Beg	2007	(32,561,650)
6	March	End	2007	(32,763,953)
7		Beg	2007	(32,763,953)
8	April	End	2007	(32,882,312)
9		Beg	2007	(32,882,312)
10	May	End	2007	(32,952,144)
11		Beg	2007	(32,952,144)
12	June	End	2007	(32,989,528)
13		Beg	2007	(32,989,528)
14	July	End	2007	(33,045,175)
15		Beg	2007	(33,045,175)
16	August	End	2007	(33,277,313)
17		Beg	2007	(33,277,313)
18	September	End	2007	(33,335,013)
19		Beg	2007	(33,335,013)
20	October	End	2007	(33,254,489)
21		Beg	2007	(33,254,489)
22	November	End	2007	(33,409,755)
23		Beg	2007	(33,409,755)
24	December	End	2007	(30,487,764)
25	Total			(789,060,249)
26				
27	Average			(32,877,510)

Cell Reference		
(1)	(4,178,445)	
FAS 158 Amount	(3,991,701)	D220 (2)

(2) Enter as a positive number on Adjustment Input Summary.

Note: The above adjustment is being made to eliminate the FAS 158 amount included in the current month activity for December 2006. The \$3,991,701 is included in each of the monthly balances shown in Column D above and therefore the entire amount is included in the 13 month average calculation. Additional explanation can be found in the testimony of Mr. Beithon.

(E)	(F)	(G)	(H)	(I)	(J)	(K)
YEAR	MONTH	SumOfCurrent Month	SumOfBalance	ACCT	SUB	
2006	12	(\$4,178,444.71)	(\$35,804,531.15)	2440	3200	(\$32,254,146)
2007	1	(\$401,603.68)	(\$36,206,224.83)	2440	3200	(\$32,687,839)
2007	2	(\$20,477.52)	(\$36,226,702.35)	2440	3200	(\$32,561,650)
2007	3	(\$167,552.76)	(\$36,394,255.11)	2440	3200	(\$32,763,953)
2007	4	(\$255,025.34)	(\$36,649,280.45)	2440	3200	(\$32,882,312)
2007	5	(\$206,498.10)	(\$36,855,778.55)	2440	3200	(\$32,952,144)
2007	6	(\$174,051.27)	(\$37,029,829.82)	2440	3200	(\$32,989,528)
2007	7	(\$192,313.11)	(\$37,222,142.93)	2440	3200	(\$33,045,175)
2007	8	(\$292,080.32)	(\$37,514,223.25)	2440	3200	(\$33,277,313)
2007	9	(\$65,415.35)	(\$37,579,638.60)	2440	3200	(\$33,335,013)
2007	10	\$252,736.71	(\$37,326,901.89)	2440	3200	(\$33,254,489)
2007	11	(\$168,726.01)	(\$37,495,627.90)	2440	3200	(\$33,409,755)
2007	12	\$2,819,212.89	(\$34,676,415.01)	2440	3200	(\$30,487,764)

YEAR	MONTH	SumOfCurrent Month	SumOfBalance	ACCT	SUB
2006	12	\$128,547.00	\$3,550,385.52	2440	3250
2007	1	(\$31,999.67)	\$3,518,385.85	2440	3250
2007	2	\$146,666.66	\$3,665,052.51	2440	3250
2007	3	(\$34,750.80)	\$3,630,301.71	2440	3250
2007	4	\$136,666.67	\$3,766,968.38	2440	3250
2007	5	\$136,666.66	\$3,903,635.04	2440	3250
2007	6	\$136,666.67	\$4,040,301.71	2440	3250
2007	7	\$136,666.67	\$4,176,968.38	2440	3250
2007	8	\$59,942.24	\$4,236,910.62	2440	3250
2007	9	\$7,715.23	\$4,244,625.85	2440	3250
2007	10	(\$172,212.50)	\$4,072,413.35	2440	3250
2007	11	\$13,459.21	\$4,085,872.56	2440	3250
2007	12	\$102,778.75	\$4,188,651.31	2440	3250

Source: GL Fire

ADJUSTMENT TO CHANGE FROM JURISDICTIONAL DIRECT ASSIGNMENT TO ALLOCATED METHOD

		(A)	(B)	(C)	(D)	(E)
Line No.	Description	Total Utility	Allocator*	Allocator %	ND	KAS Schedule 4 Reference
1	<u>PRODUCTION</u>					
2	BASE DEMAND	0	Directly Assigned minus E1	See W/P TY-01	282,214	
3	PEAK DEMAND	0	Directly Assigned minus D1	See W/P TY-01	(1,279,145)	
4	BASE ENERGY	0	Directly Assigned minus E1	See W/P TY-01	<u>0</u>	
5	TOTAL PRODUCTION				(996,931)	Col (D); Line 7
6	TRANSMISSION	0	Directly Assigned minus D2	See W/P TY-01	(820,531)	Col (D); Line 8
7	DISTRIBUTION	0	Directly Assigned minus P60	See W/P TY-01	895,541	Col (D); Line 9
8	GENERAL	0	Directly Assigned minus P90	See W/P TY-01	(131,336)	Col (D); Line 10
9	INTANGIBLE		P90	41.582448%	<u>-</u>	
10	TOTAL ACCUMULATED DEPRECIATION				<u>(1,053,257)</u>	Col (D); Line 12

*Directly Assigned means the North Dakota percent resulting from the direct assignment. The adjustment is this direct assigned percent minus the percent for the indicated allocator (E1, D1, P60, or P90).

ADJUSTMENT TO CHANGE FROM JURISDICTIONAL DIRECT ASSIGNMENT TO ALLOCATED METHOD

		(A)	(B)	(C)	(D)	(E)
Line No.	Description	Total Utility	Allocator	Allocator %	ND	PJB Schedule 8 Reference
	<u>Depreciation Expense</u>					
1	Adj to Change from Direct to Allocated Depr		Adjust ND directly	100.00%	268,864	Col (H); Line 12
2	Income Tax Impact: ND Tax Rate from Sch C-6 is 39.23%				<u>(105,462)</u>	Col (H); Line 19
3	Net Operating Income Impact				<u><u>(163,402)</u></u>	Col (H); Line 21

Otter Tail Power Company
Depreciation Allocation Adjustment

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ADJUSTMENT TO CHANGE FROM JURISDICTIONAL DIRECT ASSIGNMENT TO ALLOCATED METHOD

2007 Actual Year North Dakota CCROSS

Line No.	DEPRECIATION EXPENSE	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Allocators		Total Company	North Dakota	% as assigned (D / C)	Allocated Expense (B x C)	Test Year Adjustment (F minus D)	Input Cell #
1	PRODUCTION								
2	BASE DEMAND	E1	39.73%	7,286,535	2,798,787	38.41%	\$ 2,895,006	\$ 96,219	E621
3	PEAK DEMAND	D1	41.65%	2,847,009	1,098,184	38.57%	\$ 1,185,905	\$ 87,722	E625
4	BASE ENERGY	E1	39.73%	-	-				
5	TOTAL PRODUCTION			10,133,545	3,896,970		\$ 4,080,911	\$ 183,941	
6	TRANSMISSION	D2	41.26%	3,912,664	1,513,424	38.68%	\$ 1,614,258	\$ 100,834	E636
7	DISTRIBUTION	P60	44.34%	8,658,524	3,865,957	44.65%	\$ 3,839,338	\$ (26,619)	E643
8	GENERAL	P90	41.58%	2,275,461	935,484	41.11%	\$ 946,192	\$ 10,709	E650
9	INTANGIBLE	P90	41.58%	566,043	235,374	41.58%	\$ 235,374	\$ -	
10	TOTAL DEPRECIATION EXPENSE			25,546,236	10,447,210		\$ 10,716,074	\$ 268,864	

Note 1: Since total depreciation expense does not change, an amount equal to the ND reduction should be added to MN.

Otter Tail Power Company
Depreciation Allocation Adjustment

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ADJUSTMENT TO CHANGE FROM JURISDICTIONAL DIRECT ASSIGNMENT TO ALLOCATED METHOD

Line 2007 Actual Year North Dakota CCROSS

No.		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Allocators		Total Company	North Dakota	% as assigned (D / C)	Allocated Acc Depn (B x C)	Test Year Adjustment (F minus D)	Input Cell #
1	<u>PRODUCTION</u>								
2	BASE DEMAND	E1	39.73%	(141,591,919)	(56,537,954)	39.93%	\$ (56,255,740)	\$ 282,214	E90
3	PEAK DEMAND	D1	41.65%	(75,102,822)	(30,004,500)	39.95%	\$ (31,283,645)	\$ (1,279,145)	E94
4	BASE ENERGY	E1	39.73%	-	-				
5	TOTAL PRODUCTION			(216,694,742)	(86,542,454)		\$ (87,539,385)	\$ (996,931)	
6	TRANSMISSION	D2	41.26%	(76,356,247)	(30,681,969)	40.18%	\$ (31,502,500)	\$ (820,531)	E105
7	DISTRIBUTION	P60	44.34%	(131,655,237)	(59,273,731)	45.02%	\$ (58,378,190)	\$ 895,541	E112
8	GENERAL	P90	41.58%	(28,483,355)	(11,712,740)	41.12%	\$ (11,844,076)	\$ (131,336)	E119
9	INTANGIBLE	P90	41.58%	(1,158,266)	(481,635)	41.58%	\$ (481,635)	\$ -	
10	TOTAL ACCUMULATED DEPRECIATION			(454,347,846)	(188,692,530)		\$ (189,745,786)	\$ (1,053,257)	

Note 1: Since total accumulated depreciation does not change, an amount equal to the ND reduction should be adjusted to MN, SD and FERC in order to balance.

ADJUSTMENT FOR AMORTIZED RATE CASE EXPENSES

		(A)	(B)	(C)	(D)	(E)
Line No.	Description	Total Utility	Allocator	Allocator %	ND	PJB Schedule 8 Reference
1	2007 Rate Case Expense Adjustment	N/A	Directly Assigned	100.00%	166,667	Col (W); Line 10
2	Income Tax Impact: ND Tax Rate from Sch C-6 is 39.23%				<u>(65,375)</u>	Col (W); Line 19
3	Net Operating Income Impact				<u><u>(101,292)</u></u>	Col (W); Line 21

Otter Tail Power Company
Rate Case Expense Adjustment Calculation

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Rate Case Expense Amortization

Line No.	(A) Description	(B) Amount	(C) Entry Location
1	Rate Case Expenses	\$500,000	
2	Three Year amortization	\$166,667	F566
3	External Attorney Fees	\$250,000	
4	Administrative Costs, Consultants, etc.	200,000	
5	PSC Costs	50,000	
6	Estimated rate case expenses	<u>\$500,000</u>	

Prepared By: KSem

ADJUSTMENT FOR EMPLOYEE BENEFITS MEDICAL/DENTAL

		(A)	(B)	(C)	(D)	(E)
Line No.	Description from JCROSS INPUT SUMMARY	Total Utility	Allocator	Allocator %	ND	PJB Schedule 8 Reference
	PRODUCTION					
1	BASE DEMAND	207,525	E1	39.730897%	82,452	
2	PEAK DEMAND	102,816	D1	41.654420%	42,827	
3	TOTAL PRODUCTION EXPENSE	310,341			125,279	Col (K); Line 4
4	TRANSMISSION EXPENSES	118,807	D2	41.257266%	49,017	Col (K); Line 5
	DISTRIBUTION EXPENSES					
5	PRIMARY DEMAND	59,758	D3	44.042944%	26,319	
6	SECONDARY DEMAND	19,141	D4	45.998869%	8,805	
7	PRIMARY CUSTOMER	40,833	C2	44.100046%	18,008	
8	SECONDARY CUSTOMER	33,031	C3	44.114918%	14,572	
9	STREETLIGHTING	21,676	C4	42.050308%	9,115	
10	AREA LIGHTING	618	C5	46.540512%	287	
11	METERS	36,013	C6	43.948376%	15,827	
12	LOAD MANAGEMENT					
13	TOTAL DISTRIBUTION EXPENSE	211,071			92,934	Col (K); Line 6
	CUSTOMER ACCOUNTING EXPENSES					
14	METER READING	66,851	C7	42.205172%	28,215	
15	OTHER	84,047	C8	44.092906%	37,059	
16	TOTAL CUSTOMER ACCOUNTS	150,898			65,274	Col (K); Line 7
	CUSTOMER SERV & INFO EXP - (MN CIP)					
17	-MN	25,958	Direct	100.00%	25,958	
18	- ND	-				
19	- SD	-				
20	- OTHER	25,995	C1	43.966840%	11,429	
21	TOTAL CUSTOMER SERV & INFORMATION EXP	51,953			37,387	Col (K); Line 8
	ADMINISTRATIVE & GENERAL EXPENSES					
	SALARIES, SUPPLIES, PENSIONS & BENEFITS					
22	PRODUCTION	150,172	OXPD	40.243211%	60,434	
23	TRANSMISSION	57,482	D2	41.257266%	23,716	
24	DISTRIBUTION	102,155	OXD	44.029165%	44,978	
25	CUSTOMER ACCOUNTS	73,026	OXC	43.256597%	31,589	
26	CUSTOMER SERVICE & INFO	25,131	C1	43.966840%	11,049	
		407,966			171,766	Col (K); Line 10
27	TOTAL	1,251,037			541,657	Col (K); Line 14
28	Income Tax Impact: ND Tax Rate from Sch C-6 is 39.23%				(212,465)	Col (K); Line 19
29	Net Operating Income Impact				(329,192)	Col (K); Line 21

ADJUSTMENT FOR POSTEMPLOYMENT MEDICAL BENEFITS

		(A)	(B)	(C)	(D)	(E)
Line No.	Description from JCOSS INPUT SUMMARY	Total Utility	Allocator	Allocator %	ND	PJB Schedule 8 Reference
	PRODUCTION					
1	BASE DEMAND	12,337	E1	39.730897%	4,901	
2	PEAK DEMAND	6,112	D1	41.654420%	2,546	
3	TOTAL PRODUCTION EXPENSE	18,449			7,448	Col (M); Line 4
4	TRANSMISSION EXPENSES	7,063	D2	41.257266%	2,915	Col (M); Line 5
	DISTRIBUTION EXPENSES					
5	PRIMARY DEMAND	3,552	D3	44.042944%	1,565	
6	SECONDARY DEMAND	1,138	D4	45.998869%	523	
7	PRIMARY CUSTOMER	2,427	C2	44.100046%	1,070	
8	SECONDARY CUSTOMER	1,964	C3	44.114918%	866	
9	STREETLIGHTING	1,289	C4	42.050308%	542	
10	AREA LIGHTING	37	C5	46.540512%	17	
11	METERS	2,141	C6	43.948376%	941	
12	LOAD MANAGEMENT	-				
13	TOTAL DISTRIBUTION EXPENSE	12,547			5,524	Col (M); Line 6
	CUSTOMER ACCOUNTING EXPENSES					
14	METER READING	3,974	C7	42.205172%	1,677	
15	OTHER	4,996	C8	44.092906%	2,203	
16	TOTAL CUSTOMER ACCOUNTS	8,970			3,880	Col (M); Line 7
	CUSTOMER SERV & INFO EXP - (MN CIP)					
17	-MN	1,543	Direct	100.00%	1,543	
18	- ND					
19	- SD					
20	- OTHER	1,545	C1	43.966840%	679	
21	TOTAL CUSTOMER SERV & INFORMATION EXP	3,088			2,223	Col (M); Line 8
	ADMINISTRATIVE & GENERAL EXPENSES					
	SALARIES, SUPPLIES, PENSIONS & BENEFITS					
22	PRODUCTION	8,927	OXPD	40.243211%	3,593	
23	TRANSMISSION	3,417	D2	41.257266%	1,410	
24	DISTRIBUTION	6,073	OXD	44.029165%	2,674	
25	CUSTOMER ACCOUNTS	4,341	OXC	43.256597%	1,878	
26	CUSTOMER SERVICE & INFO	1,494	C1	43.966840%	657	
		24,252			10,211	Col (M); Line 10
27	TOTAL	74,369			32,200	Col (M); Line 14
28	Income Tax Impact: ND Tax Rate from Sch C-6 is 39.23%				(12,631)	Col (M); Line 19
29	Net Operating Income Impact				(19,570)	Col (M); Line 21

ADJUSTMENT FOR POST RETIREMENT BENEFITS

Line No.	Description from JCOSS INPUT SUMMARY	(A) Total Utility	(B) Allocator	(C) Allocator %	(D) ND	(E) PJB Schedule 8 Reference
1	PRODUCTION					
1	BASE DEMAND	48,977	E1	39.730897%	19,459	
2	PEAK DEMAND	24,265	D1	41.654420%	10,107	
3	TOTAL PRODUCTION EXPENSE	73,242			29,568	Col (M); Line 4
4	TRANSMISSION EXPENSES	28,039	D2	41.257266%	11,569	Col (M); Line 5
5	DISTRIBUTION EXPENSES					
5	PRIMARY DEMAND	14,103	D3	44.042944%	6,211	
6	SECONDARY DEMAND	4,517	D4	45.998869%	2,078	
7	PRIMARY CUSTOMER	9,637	C2	44.100046%	4,250	
8	SECONDARY CUSTOMER	7,796	C3	44.114918%	3,439	
9	STREETLIGHTING	5,116	C4	42.050308%	2,151	
10	AREA LIGHTING	146	C5	46.540512%	68	
11	METERS	8,499	C6	43.948376%	3,735	
12	LOAD MANAGEMENT	-				
13	TOTAL DISTRIBUTION EXPENSE	49,814			21,933	Col (M); Line 6
14	CUSTOMER ACCOUNTING EXPENSES					
14	METER READING	15,777	C7	42.205172%	6,659	
15	OTHER	19,835	C8	44.092906%	8,746	
16	TOTAL CUSTOMER ACCOUNTS	35,613			15,405	Col (M); Line 7
17	CUSTOMER SERV & INFO EXP - (MN CIP)					
17	-MN	6,126	Direct	100.00%	6,126	
18	- ND					
19	- SD					
20	- OTHER	6,135	C1	43.966840%	2,697	
21	TOTAL CUSTOMER SERV & INFORMATION EXP	12,261			8,824	Col (M); Line 8
22	ADMINISTRATIVE & GENERAL EXPENSES					
22	SALARIES, SUPPLIES, PENSIONS & BENEFITS					
22	PRODUCTION	35,441	OXPD	40.243211%	14,263	
23	TRANSMISSION	13,566	D2	41.257266%	5,597	
24	DISTRIBUTION	24,109	OXD	44.029165%	10,615	
25	CUSTOMER ACCOUNTS	17,234	OXC	43.256597%	7,455	
26	CUSTOMER SERVICE & INFO	5,931	C1	43.966840%	2,608	
		96,282			40,538	Col (M); Line 10
27	TOTAL	295,251			127,834	Col (M); Line 14
28	Income Tax Impact: ND Tax Rate from Sch C-6 is 39.23%				(50,143)	Col (M); Line 19
29	Net Operating Income Impact				(77,691)	Col (M); Line 21

ADJUSTMENT FOR FASB 87 PENSION COSTS

Line No.	Description from JCOSS INPUT SUMMARY	(A) Total Utility	(B) Allocator	(C) Allocator %	(D) ND	(E) PJB Schedule 8 Reference
	PRODUCTION					
1	BASE DEMAND	(226,859)	E1	37.202590%	(84,397)	
2	PEAK DEMAND	(112,395)	D1	39.542883%	(44,444)	
3	TOTAL PRODUCTION EXPENSE	(339,254)			(128,842)	Col (L); Line 4
4	TRANSMISSION EXPENSES	(129,876)	D2	39.150834%	(50,847)	Col (L); Line 5
	DISTRIBUTION EXPENSES					
5	PRIMARY DEMAND	(65,325)	D3	43.928211%	(28,696)	
6	SECONDARY DEMAND	(20,925)	D4	46.013482%	(9,628)	
7	PRIMARY CUSTOMER	(44,638)	C2	44.100046%	(19,685)	
8	SECONDARY CUSTOMER	(36,109)	C3	44.114918%	(15,929)	
9	STREETLIGHTING	(23,696)	C4	42.050308%	(9,964)	
10	AREA LIGHTING	(675)	C5	46.540512%	(314)	
11	METERS	(39,368)	C6	43.948376%	(17,302)	
12	LOAD MANAGEMENT					
13	TOTAL DISTRIBUTION EXPENSE	(230,735)			(101,519)	Col (L); Line 6
	CUSTOMER ACCOUNTING EXPENSES					
14	METER READING	(73,079)	C7	42.205172%	(30,843)	
15	OTHER	(91,877)	C8	44.092906%	(40,511)	
16	TOTAL CUSTOMER ACCOUNTS	(164,956)			(71,354)	Col (L); Line 7
	CUSTOMER SERV & INFO EXP - (MN CIP)					
17	-MN	(28,376)	Direct	100.00%	(28,376)	
18	- ND					
19	- SD					
20	- OTHER	(28,417)	C1	43.966840%	(12,494)	
21	TOTAL CUSTOMER SERV & INFORMATION EXP	(56,793)			(40,870)	Col (L); Line 8
	ADMINISTRATIVE & GENERAL EXPENSES					
	SALARIES, SUPPLIES, PENSIONS & BENEFITS					
22	PRODUCTION	(164,163)	OXPD	37.818105%	(62,083)	
23	TRANSMISSION	(62,838)	D2	39.150834%	(24,601)	
24	DISTRIBUTION	(111,672)	OXD	43.998008%	(49,133)	
25	CUSTOMER ACCOUNTS	(79,829)	OXC	43.256597%	(34,531)	
26	CUSTOMER SERVICE & INFO	(27,472)	C1	43.966840%	(12,079)	
		(445,974)			(182,429)	Col (L); Line 10
27	TOTAL	(1,367,587)			(575,861)	Col (L); Line 14
28	Income Tax Impact: ND Tax Rate from Sch C-6 is 39.23%				225,882	Col (L); Line 19
29	Net Operating Income Impact				349,980	Col (L); Line 21

Otter Tail Power Company
Medical, FAS 106 (Postretirement Benefits) & 112 (Postemployment Benefits) and FAS 87 (Pension)

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
				Medical	Cell	FAS 112	Cell	FAS 106	Cell	FAS 87	Cell	Total
	PRODUCTION											
1	BASE DEMAND	11,325,547	67%	207,525	G469	12,337	H469	48,977	I469	(226,859)	J469	41,980
2	PEAK DEMAND	5,611,117	33%	102,816	G470	6,112	H470	24,265	I470	(112,395)	J470	20,798
3	TOTAL PRODUCTION EXPENSE	16,936,664	100%	310,341		18,449		73,242		(339,254)		62,778
4	TRANSMISSION EXPENSES			118,807	G490	7,063	H490	28,039	I490	(129,876)	J490	24,033
	<u>DISTRIBUTION EXPENSES</u>											
5	PRIMARY DEMAND	4,157,949	28%	59,758	G493	3,552	H493	14,103	I493	(65,325)	J493	12,088
6	SECONDARY DEMAND	1,331,858	9%	19,141	G494	1,138	H494	4,517	I494	(20,925)	J494	3,872
7	PRIMARY CUSTOMER	2,841,193	19%	40,833	G495	2,427	H495	9,637	I495	(44,638)	J495	8,260
8	SECONDARY CUSTOMER	2,298,330	16%	33,031	G496	1,964	H496	7,796	I496	(36,109)	J496	6,682
9	STREETLIGHTING	1,508,249	10%	21,676	G497	1,289	H497	5,116	I497	(23,696)	J497	4,385
10	AREA LIGHTING	42,974	0%	618	G498	37	H498	146	I498	(675)	J498	125
11	METERS	2,505,796	17%	36,013	G499	2,141	H499	8,499	I499	(39,368)	J499	7,285
12	LOAD MANAGEMENT	-				-						
13	TOTAL DISTRIBUTION EXPENSE	14,686,349	100%	211,071		12,547		49,814		(230,735)		42,697
	<u>CUSTOMER ACCOUNTING EXPENSES</u>											
14	METER READING	4,654,956	44%	66,851	G505	3,974	H505	15,777	I505	(73,079)	J505	13,523
15	OTHER	5,852,304	56%	84,047	G506	4,996	H506	19,835	I506	(91,877)	J506	17,002
16	TOTAL CUSTOMER ACCOUNTS	10,507,260	100%	150,898		8,970		35,613		(164,956)		30,525
	<u>CUSTOMER SERV & INFO EXP - (MN CIP)</u>											
17	-MN	2,618,980	50%	25,958	G510	1,543	H510	6,126	I510	(28,376)	J510	5,251
18	-ND	-										
19	-SD	-										
20	-OTHER	2,622,720	50%	25,995	G513	1,545	H513	6,135	I513	(28,417)	J513	5,258
21	TOTAL CUSTOMER SERV & INFORMATION EXP	5,241,700	100%	51,953		3,088		12,261		(56,793)		10,509
	<u>ADMINISTRATIVE & GENERAL EXPENSES</u>											
	<u>SALARIES, SUPPLIES, PENSIONS & BENEFITS</u>											
22	PRODUCTION	8,158,582	37%	150,172	G551	8,927	H551	35,441	I551	(164,163)	J551	30,378
23	TRANSMISSION	3,122,913	14%	57,482	G552	3,417	H552	13,566	I552	(62,838)	J552	11,628
24	DISTRIBUTION	5,549,875	25%	102,155	G553	6,073	H553	24,109	I553	(111,672)	J553	20,665
25	CUSTOMER ACCOUNTS	3,967,362	18%	73,026	G554	4,341	H554	17,234	I554	(79,829)	J554	14,772
26	CUSTOMER SERVICE & INFO	1,365,305	6%	25,131	G555	1,494	H555	5,931	I555	(27,472)	J555	5,064
27				407,966		24,252		96,282		(445,974)		82,527
28	TOTAL A&G SALARIES, SUPP, PENSIONS & BENEFIT	22,164,037	100%									
29	TOTAL			1,251,037		74,369		295,251		(1,367,587)		253,070

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Otter Tail Power Company
Medical, FAS 106 (Postretirement Benefits) & 112 (Postemployment Benefits) and FAS 87 (Pension)

Line No.	(A) Labor From FERC Form 1 Page 354-355	(B) Amount	(C) % of total	(D) Medical	(E) FAS 112	(F) FAS 106	(G) FAS 87	(H) Total
1	Production	\$ 14,906,456	21.1%	\$ 310,341	\$ 18,449	\$ 73,242	\$ (339,254)	\$ 62,778
2	Transmission	5,706,607	8.1%	118,807	7,063	28,039	\$ (129,876)	24,033
3	Distribution	10,138,266	14.4%	211,071	12,547	49,814	\$ (230,735)	42,697
4	Customer Accounts	7,247,999	10.3%	150,898	8,970	35,613	\$ (164,956)	30,525
5	Customer Service & Information, & Sales	2,495,421	3.5%	51,953	3,088	12,261	\$ (56,793)	10,509
6	Administrative & General	19,595,620	27.8%	407,966	24,252	96,282	(445,974)	82,527
7	Total Labor Expense	\$ 60,090,369		\$ 1,251,037	\$ 74,369	\$ 295,251	\$ (1,367,587)	\$ 253,070
8	Construction Labor	9,230,786	13.1%	192,178	11,424	45,355	(210,082)	38,875
9	Total Utility Labor	\$ 69,321,155		\$ 1,443,215	\$ 85,793	\$ 340,606	\$ (1,577,669)	\$ 291,946
10	Account 417.1 Expenses of Non-Utility Operations	1,161,698	1.6%	24,186	1,438	5,708	(26,439)	4,892
11	Total Otter Tail Power Labor	\$ 70,482,853	100.0%	\$ 1,467,401	\$ 87,231	\$ 346,314	\$ (1,604,108)	\$ 296,838

Otter Tail Power Company
Medical, FAS 106 (Postretirement Benefits) & 112 (Postemployment Benefits) and FAS 87 (Pension)
Adjustment Calculations

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Year	Medical & Dental ^{*, **}	Medical % Increase	FAS 112 Expense (Post Employment Medical)**	FAS 112 Expense % Increase	FAS 106 Expense (Post Retirement Medical)**	FAS 106 Expense % Increase	Fas 87 Pension Expense	FAS 87 Pension % Increase	Total expenses	Total % change
2003	\$ 6,040,289	--	\$ (49,043)	--	\$ 4,574,189	--	\$ 1,442,403	--	\$ 12,007,838	--
2004	\$ 6,765,286	12.00%	\$ 569,970	1262.18%	\$ 3,944,860	-13.76%	\$ 1,885,326	30.71%	\$ 13,165,442	9.64%
2005	\$ 7,037,358	4.02%	\$ 1,983,077	247.93%	\$ 3,532,466	-10.45%	\$ 4,210,262	123.32%	\$ 16,763,163	27.33%
2006	\$ 8,236,703	17.04%	\$ 258,193	-86.98%	\$ 3,135,356	-11.24%	\$ 5,449,510	29.43%	\$ 17,079,762	1.89%
2007	\$ 8,304,645	0.82%	\$ 217,619	-15.71%	\$ 2,936,686	-6.34%	\$ 4,230,508	-22.37%	\$ 15,689,458	-8.14%
2008	\$ 9,772,046	17.67%	\$ 304,850	40.08%	\$ 3,283,000	11.79%	\$ 2,626,400	-37.92%	\$ 15,986,296	1.89%
Adjustment	\$ 1,467,401		\$ 87,231		\$ 346,314		\$ (1,604,109)		\$ 296,838	
5-year Average	\$ 7,276,856		\$ 595,963		\$ 3,624,711		\$ 3,443,602		\$ 14,941,133	
3-year average	\$ 7,859,569		\$ 819,630		\$ 3,201,503		\$ 4,630,093		\$ 16,510,794	
3Yr Avg Adj	\$ (445,076)		\$ 602,011		\$ 264,817		\$ 399,585		\$ 821,336	

* 2008 projected based on actual claims data of January - March 2008 and renewal projections for the remainder of the year.

** 2006 recognized the impact of Medicare Part D subsidy

ADJUSTMENT FOR CORPORATE ALLOCATIONS

		(A)	(B)	(C)	(D)	(E)
Line No.	Description	Total Utility	Allocator	Allocator %	ND	PJB Schedule 8 Reference
1	ADMINISTRATIVE & GENERAL EXPENSES					
	SALARIES, SUPPLIES, PENSIONS & BENEFITS					
2	PRODUCTION	(36,574)	OXPD	40.243211%	(14,719)	
3	TRANSMISSION	(13,999)	D2	41.257266%	(5,776)	
4	DISTRIBUTION	(24,879)	OXD	44.029165%	(10,954)	
5	CUSTOMER ACCOUNTS	(17,786)	OXC	43.256597%	(7,694)	
6	CUSTOMER SERVICE & INFO	<u>(6,120)</u>	C1	43.966840%	<u>(2,691)</u>	
	TOTAL A&G SALARIES, SUPPLIES, PENSIONS AND BENEFITS	<u>(99,358)</u>			(41,833)	Col (V); Line 10
8	Income Tax Impact: ND Tax Rate from Sch C-6 is 39.23%				<u>16,409</u>	Col (V); Line 19
9	Net Operating Income Impact				<u>25,424</u>	Col (V); Line 21

Otter Tail Power Company
Allocation of Adjustment to Corporate Allocations

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Line No.	(A) Description from JCROSS INPUT SUMMARY	(B) From 2007 Actual Functionalization	(C) Adjustment	(D) Input Summary Cell #
	ADMINISTRATIVE & GENERAL EXPENSES			
	SALARIES, SUPPLIES, PENSIONS & BENEFITS			
1	PRODUCTION	8,158,582	(36,574)	K551
2	TRANSMISSION	3,122,913	(13,999)	K552
3	DISTRIBUTION	5,549,875	(24,879)	K553
4	CUSTOMER ACCOUNTS	3,967,362	(17,786)	K554
5	CUSTOMER SERVICE & INFO	1,365,305	(6,120)	K555
6	TOTAL A&G SALARIES, SUPPLIES, PENSIONS & BENEFITS	22,164,036	(99,358)	
7	Total Corporate labor - 2007	13,390,532		
8	Average Corporate labor increase effective January 2008	5.4%		
9	Corporate labor increase	720,411		
10	Total Corporate labor after 2008 average increase	14,110,942		
11	Average Corporate labor increase effective January 2009	4.0%		
12	Corporate labor increase	564,438		
13	Total Corporate labor increases 2008-2009	1,284,848		
14	Otter Tail Power Company portion	30.0%		
15	Test year increase in utility portion of Corporate costs	216,426	216,426	
16	Reduction to utility allocated corporate costs for capped officer bonuses	See p 2	(315,784)	
17	Net Test Year Adjustment		(99,358)	

Prepared By: KSem

Otter Tail Power Company
Adjustment to Cap Corporate Bonuses at 25%

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Line No.	(A) From Proxy Statement for 2007		(B) Officers'	(C) Cash Bonus	Bonus capped at 25%	(D) Allocated to OTP		(E) Officers'	(F) Cash Bonus	Bonus capped at 25%
			Salaries					Salaries		
1	JE		453,500	408,016	113,375	218,469	196,558	54,617		
2	KM		295,000	168,798	73,750	121,319	69,418	30,330		
3	LM		360,500	324,274	90,125	170,938	153,761	42,735		
4	GK		252,500	119,563	63,125	106,156	50,267	26,539		
5	Total		1,361,500	1,020,651	340,375	616,882	470,004	154,221		
6	Non Exec (two over 25%)		348,101	155,408	87,025			0		
7	Non Exec (remainder; none over 25%)			423,985	423,985		183,041	183,041		
8	OTTR Bonuses			1,600,044	851,385		653,045	337,262		
9										
10										
11	OTP share of total bonuses	line 8(b) x line 20			653,045					
12	OTP share of capped bonuses	line 8(c) x line 20			337,262					
13	Adjustment to corporate allocations				(315,784)					
14										
15	<i>Development of OTP share of bonuses</i>									
16	2007 Corporate Costs									
17	OTP share of all labor	line 35(A) of page 4 of 4.			30.0%					
18										
19										
20	OTP share of bonuses	line 8(e) / line 8(b)			40.8%					

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Otter Tail Corporation
Corporate Allocations
Year-To-Date - December 31, 2007

Line No.		(A)	(B)	(C)	(D)
1	Allocated to Otter Tail Power	\$ 6,599,861	31.08%		
2	Allocated to Varistar	11,210,723	52.79%		
3	Kept at Corporate	3,427,232	16.14%		
4	Total YTD Corporate Costs	<u>\$ 21,237,816</u>	<u>100.00%</u>		
5					
6	Allocated by:	Otter Tail Power	Varistar	Corporate	Total
7	Direct Charge	\$ 2,716,120	\$ 5,280,518	\$ 3,427,232	\$ 11,423,871
8	Indirect Allocation	1,421,486	2,144,995		3,566,481
9	General Allocator	2,462,254	3,785,210		6,247,465
10	Total	<u>\$ 6,599,861</u>	<u>\$ 11,210,723</u>	<u>\$ 3,427,232</u>	<u>\$ 21,237,816</u>
11		31.08%	52.79%	16.14%	100.00%
12					
13	Allocated by:	Otter Tail Power	Varistar	Corporate	Total
14	Direct Charge	23.78%	46.22%	30.00%	100.00%
15	Indirect Allocation	39.86%	60.14%	0.00%	100.00%
16	General Allocator	39.41%	60.59%	0.00%	100.00%
17	Total	<u>31.08%</u>	<u>52.79%</u>	<u>16.14%</u>	<u>100.00%</u>
18					
19	Adjustments to be made to 2007 actual corporate costs				
20	5% Wage Increase	\$ 201,139	\$ 368,458	\$ 99,929	\$ 669,527
21	25% Bonus Cap	(315,784)		315,784	
22		<u>\$ (114,644)</u>	<u>\$ 368,458</u>	<u>\$ 415,713</u>	<u>\$ 669,527</u>
23					
24					
25		Otter Tail Power	Varistar	Corporate	Total
26	Labor and labor related costs	\$ 4,022,789	\$ 7,369,163	\$ 1,998,580	\$ 13,390,532
27	Other costs	2,577,072	3,841,561	1,428,652	7,847,285
28	Total	<u>\$ 6,599,861</u>	<u>\$ 11,210,723</u>	<u>\$ 3,427,232</u>	<u>\$ 21,237,816</u>
29					
30		Otter Tail Power	Varistar	Corporate	Total
31	Labor and labor related costs	\$ 4,022,789	\$ 7,369,163	\$ 1,998,580	\$ 13,390,532
32	Total	6,599,861	11,210,723	3,427,232	21,237,816
33	Labor percent of total	60.95%	65.73%	58.31%	63.05%
34					
35	Percent of total labor	30.04%	55.03%	14.93%	100.00%

ADJUSTMENT TO ACCUMULATED DEPRECIATION TO REFLECT 2008 RATES

		(A)	(B)	(C)	(D)	(E)
Line No.	Description	Total Utility	Allocator	Allocator %	ND	KAS Schedule 4 Reference
1	<u>PRODUCTION</u>					
2	BASE DEMAND	(130,787)	E1	39.730897%	(51,963)	
3	PEAK DEMAND	(2,625)	D1	41.654420%	(1,093)	
4	BASE ENERGY	<u>-</u>	E1	39.730897%	<u>0</u>	
5	TOTAL PRODUCTION	(133,412)			(53,056)	Col (E); Line 7
6	TRANSMISSION	51,675	D2	41.257266%	21,320	Col (E); Line 8
7	DISTRIBUTION	38,896	P60	44.341715%	17,247	Col (E); Line 9
8	GENERAL	5,864	P90	40.825142%	2,394	Col (E); Line 10
9	INTANGIBLE	<u>-</u>	P90	40.825142%	<u>-</u>	
10	TOTAL DEPRECIATION EXPENSE	<u>(36,977)</u>			<u>(12,095)</u>	Col (E); Line 12

ADJUSTMENT FOR DEPRECIATION EXPENSE TO REFLECT 2008 RATES

		(A)	(B)	(C)	(D)	(E)
Line No.	Description	Total Utility	Allocator	Allocator %	ND	PJB Schedule 8 Reference
1	<u>PRODUCTION</u>					
2	BASE DEMAND	130,787	E1	39.730897%	51,963	
3	PEAK DEMAND	2,625	D1	41.654420%	1,093	
4	BASE ENERGY	-	E1	39.730897%	0	
5	TOTAL PRODUCTION	133,412			53,056	
6	TRANSMISSION	(51,675)	D2	41.257266%	(21,320)	
7	DISTRIBUTION	(38,896)	P60	44.341715%	(17,247)	
8	GENERAL	(5,864)	P90	40.825142%	(2,394)	
9	INTANGIBLE	-	P90	40.825142%	-	
10	TOTAL DEPRECIATION EXPENSE	36,977			12,095	Col (J); Line 12
11	Income Tax Impact: ND Tax Rate from Sch C-6 is 39.23%				<u>(4,744)</u>	Col (J); Line 19
12	Net Operating Income Impact				<u>(7,351)</u>	Col (J); Line 21

Note: Combined with Adjustment for 2009 Rates in Col (J) of Exhibit__(PJB-1), Schedule 8

2007 Actual Year North Dakota CCROSS

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IMPACT OF USING 2008 DEPRECIATION RATES

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	DEPRECIATION EXPENSE	Allocators	Total Company (2)	Allocated to North Dakota	Input Cell #	North Dakota Expense per Filing (3)	Difference	Remaining (1)	Input Line #
1	PRODUCTION	E1	130,787	51,963	L621; L90	\$ 49,555	\$ (2,408)	78,824	L620; L89
2	BASE DEMAND	D1	2,625	1,093	L625; L94	\$ 1,028	\$ (65)	1,532	L624; L93
3	PEAK DEMAND	E1	-	-					
4	BASE ENERGY								
5	TOTAL PRODUCTION		133,412	53,056		\$ 50,583	\$ (2,473)	80,356	
6	TRANSMISSION	D2	(51,675)	(21,320)	L636; L105	\$ (20,000)	\$ 1,320	(30,355)	L635; L104
7	DISTRIBUTION	P60	(38,896)	(17,247)	L643; L112	\$ (17,364)	\$ (117)	(21,649)	L642; L111
8	GENERAL	P90	(5,864)	(2,394)	L650; L119	\$ (2,404)	\$ (10)	(3,470)	L649; L118
9	INTANGIBLE	P90	-	-		\$ -	\$ -		
10	TOTAL DEPRECIATION EXPENSE		36,977	12,095		\$ 10,815	\$ (1,280)	24,882	

- (1) Since this is an increase in total depreciation expense, the remainder has been entered in MN on the Input Summary in order to have the correct total expense.
- (2) The adjustment amounts are found in the ND informational depreciation filing submitted each year.
- (3) Estimated impact shown in the informational filing is not used here; rather the total impact is allocated to North Dakota consistent with the requested change in allocation methodology for depreciation expense in this case.

Note: The Inputs for Accumulated Depreciation are the opposite sign as the numbers shown above for expense.

ADJUSTMENT FOR DEPRECIATION EXPENSE TO REFLECT 2009 RATES

		(A)	(B)	(C)	(D)	(E)
Line						KAS
No.	Description	Total Utility	Allocator	Allocator %	ND	Schedule 4 Reference
1	<u>PRODUCTION</u>					
2	BASE DEMAND	(29,370)	E1	39.730897%	(11,669)	
3	PEAK DEMAND	(57,255)	D1	41.654420%	(23,849)	
4	BASE ENERGY	<u>-</u>	E1	39.730897%	<u>0</u>	
5	TOTAL PRODUCTION	(86,625)			(35,518)	Col (F); Line 14
6	TRANSMISSION	263,103	D2	41.257266%	108,549	Col (F); Line 15
7	DISTRIBUTION	98,325	P60	44.341715%	43,599	Col (F); Line 16
8	GENERAL	226,612	P90	40.825142%	92,515	Col (F); Line 17
9	INTANGIBLE	<u>-</u>	P90	40.825142%	<u>-</u>	
10	TOTAL DEPRECIATION EXPENSE	<u>501,415</u>			<u>209,145</u>	Col (F); Line 19

ADJUSTMENT FOR DEPRECIATION EXPENSE TO REFLECT 2009 RATES

Line No.	Description	(A) Total Utility	(B) Allocator	(C) Allocator %	(D) ND	(E) PJB Schedule 8 Reference
1	<u>PRODUCTION</u>					
2	BASE DEMAND	29,370	E1	39.730897%	11,669	
3	PEAK DEMAND	57,255	D1	41.654420%	23,849	
4	BASE ENERGY	-	E1	39.730897%	0	
5	TOTAL PRODUCTION	86,625			35,518	
6	TRANSMISSION	(263,103)	D2	41.257266%	(108,549)	
7	DISTRIBUTION	(98,325)	P60	44.341715%	(43,599)	
8	GENERAL	(226,612)	P90	40.825142%	(92,515)	
9	INTANGIBLE	-	P90	40.825142%	-	
10	TOTAL DEPRECIATION EXPENSE	(501,415)			(209,145)	Col (J); Line 12
11	Income Tax Impact: ND Tax Rate from Sch C-6 39.23%				82,037	Col (J); Line 19
12	Net Operating Income Impact				127,108	Col (J); Line 21

Note: Combined with Adjustment for 2008 Rates in Col (J) of Exhibit__(PJB-1), Schedule 8

2007 Actual Year North Dakota CCROSS
IMPACT OF USING 2009 DEPRECIATION RATES

DEPRECIATION EXPENSE							(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.													
1	PRODUCTION												
2	BASE DEMAND	E1	39.73%	29,370	11,669	M621; M90	17,701	M620; M89					
3	PEAK DEMAND	D1	41.65%	57,255	23,849	M625; M94	33,406	M624; M93					
3	BASE ENERGY	E1	39.73%	-	-								
1	TOTAL PRODUCTION			86,625	35,518		51,107						
2	TRANSMISSION	D2	41.26%	(263,103)	(108,549)	M636; M105	(154,554)	M635; M104					
3	DISTRIBUTION	P60	44.34%	(98,325)	(43,599)	M643; M112	(54,726)	M642; M111					
4	GENERAL	P90	40.83%	(226,612)	(92,515)	M650; M119	(134,097)	M649; M118					
5	INTANGIBLE	P90	40.83%	-	-								
9	TOTAL DEPRECIATION EXPENSE			(501,415)	(209,145)		(292,270)						

- (1) Since this is an increase in total depreciation expense, the remainder has been entered in MN on the Input Summary in order to have the correct total expense.
- (2) The adjustment amounts are found in the proposed MN depreciation filing submitted on September 1, 2008.

Note: The Inputs for Accumulated Depreciation are the opposite sign as the numbers shown above for expense.

ADJUSTMENT FOR ECONOMIC DEVELOPMENT

		(A)	(B)	(C)	(D)	(E)
Line No.	Description	Total Utility	Allocator	Allocator %	ND	PJB Schedule 8 Reference
1	2007 Economic Development Adjustment	N/A	Directly Assigned	100.00%	72,492	Col (U); Line 9
2	Income Tax Impact ND: Tax Rate from Sch C-6 is 39.23%				(28,435)	Col (U); Line 19
3	Net Operating Income Impact				(44,057)	Col (U); Line 21

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Otter Tail Power Company
Test Year Adjustment
Economic Development Expensed
2003 - 2007

(A)	(B)	(C)
	<u>2007 Test Year Amount</u>	<u>2007 Actual Amount</u>
Economic Development Expenses	500,000	427,508
Adjustment to 2007 account 912 (A) - (B)	<u><u>72,492</u></u>	Enter in CELL N543 test year adjustments tab

Source: 2007 Functionalization 5 yr Average History

ADJUSTMENT DUE TO LOAD INCREASE

		(A)	(B)	(C)	(D)	(E)
Line No.	Description	Total Utility	Allocator	Allocator %	ND	PJB Schedule 8 Reference
1	2007 Adjustment Due to Load Increase Revenue	N/A	Directly Assigned	100.00%	<u>8,882,240</u>	Col (B); Line 1
2	2007 Adjustment Due to Load Increase - Base Demand	379,950	E1	39.730897%	150,958	
3	2007 Adjustment Due to Load Increase - Base Energy	6,956,559	E2	41.017975%	<u>2,853,440</u>	
4	Total Expense Adjustment				<u>3,004,397</u>	Col (B); Line 4
5	Operating Income Impact				5,877,843	
6	Income Tax Impact ND: Tax Rate from Sch C-6 is 39.23%				<u>(2,305,584)</u>	Col (B); Line 19
7	Net Operating Income Impact				<u>3,572,259</u>	Col (B); Line 21

Otter Tail Power Company
Adjustment Due to Load Increase

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Month	KW	kWh	Revenue	Monthly COE Adj	COE Revenue	Total Revenue Adjustment	Cell Reference
1	1	20	13,500,000	\$538,700	\$0.01160	\$156,600	\$695,300	
2	2	20	13,500,000	\$538,700	\$0.01380	\$186,300	\$725,000	
3	3	20	13,500,000	\$538,700	\$0.01390	\$187,650	\$726,350	
4	4	20	13,500,000	\$538,700	\$0.01810	\$244,350	\$783,050	
5	5	20	13,500,000	\$538,700	\$0.01980	\$267,300	\$806,000	
6	6	20	13,500,000	\$538,700	\$0.02160	\$291,600	\$830,300	
7	7	22	15,100,000	\$602,300	\$0.01990	\$300,490	\$902,790	
8	8	22	15,100,000	\$602,300	\$0.01640	\$247,640	\$849,940	
9	9	22	15,100,000	\$602,300	\$0.01050	\$158,550	\$760,850	
10	10	22	15,100,000	\$602,300	\$0.00260	\$39,260	\$641,560	
11	11	20	13,500,000	\$538,700	\$0.00260	\$35,100	\$573,800	
12	12	20	13,500,000	\$538,700	\$0.00360	\$48,600	\$587,300	
13		20	168,400,000	\$6,718,800		\$2,163,440	\$8,882,240	P389 on Adj Details Tab D849 on ND Input Tab
Expense Adjustment								
14	COE budget 12/08 - 11/09		average purchase price	0.04130973			per kWh	
15			purchase cost	\$6,956,559				P481 on Details Tab
16			Cost/MW					
17	winter capacity		\$500	\$60,000				
18	summer capacity		\$2,500	319,950				
18	Total capacity cost			\$379,950				P479 on Details Tab

REVENUE ADJUSTMENT DUE TO BILLING CHANGE

		(A)	(B)	(C)	(D)	(E)
Line No.	Description	Total Utility	Allocator	Allocator %	ND	PJB Schedule 8 Reference
1	Other Miscellaneous Revenue Increase	451,503	NEPIS	42.050142%	189,857	Col (C); Line 2
2	Income Tax Impact: ND Tax Rate from Sch C-6 is 39.23%				74,472	Col (C); Line 19
3	Net Operating Income Impact				115,386	Col (C); Line 21

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Revenue Adjustment Due to Billing Change

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	(A)	(B)	(C)	(D)	(E)
Line No.		Projected Increase in Big Stone Plant Steam Revenue	OTP's Ownership % of BS Plant	Test Year Adjustment	Cell Reference
1	Other Miscellaneous Electric Revenue	837,667	53.90%	451,503	Q421

Note: The method of billing an Ethanol Plant served by Otter Tail Power Company for steam use at the Big Stone Plant was changed to billing on an hourly basis which is based off a market price. The change became effective on January 17, 2008 and results in a projected increase in revenue of \$837,667. Otter Tail Power Company has a 53.9% ownership in the Big Stone Plant.

Prepared By: KSem

ADJUSTMENT FOR 2008 & 2009 APRIL AND NOVEMBER ANNUAL WAGE INCREASES

	(A)	(B)	(C)	(D)	(E)
Line No.	Total Utility	Allocator	Allocator %	ND	PJB Schedule 8 Reference
PRODUCTION					
1	530,409	E1	39.730897%	210,736	
2	262,785	D1	41.654420%	109,462	
3	793,195			320,198	Col (O); Line 4
4	303,657	D2	41.257266%	125,281	Col (O); Line 5
DISTRIBUTION EXPENSES					
5	152,734	D3	44.042944%	67,268	
6	48,923	D4	45.998869%	22,504	
7	104,365	C2	44.100046%	46,025	
8	84,424	C3	44.114918%	37,244	
9	55,402	C4	42.050308%	23,297	
10	1,579	C5	46.540512%	735	
11	92,045	C6	43.948376%	40,452	
12					
13	539,472			237,524	Col (O); Line 6
CUSTOMER ACCOUNTING EXPENSES					
14	170,864	C7	42.205172%	72,113	
15	214,813	C8	44.092906%	94,717	
16	385,677			166,831	Col (O); Line 7
CUSTOMER SERV & INFO EXP - (MN CIP)					
17	66,345	Direct	100.00%	-	
18					
19					
20	66,440	C1	43.966840%	29,212	
21	132,785			29,212	Col (O); Line 8
ADMINISTRATIVE & GENERAL EXPENSES					
SALARIES, SUPPLIES, PENSIONS & BENEFITS					
22	390,183	OXPD	40.243211%	157,022	
23	155,573	D2	41.257266%	64,185	
24	245,142	OXD	44.029165%	107,934	
25	186,437	OXC	43.256597%	80,646	
26	65,378	C1	43.966840%	28,745	
	1,042,712			438,532	Col (O); Line 10
27	3,197,498			1,317,578	Col (O); Line 14
28	Income Tax Impact: ND Tax Rate from Sch C-6 is 39.23%			(516,820)	Col (O); Line 19
29	Net Operating Income Impact			(800,758)	Col (O); Line 21

ADJUSTMENT FOR KPA AND UTILITY MANAGEMENT INCENTIVES

	(A)	(B)	(C)	(D)	(E)
Line No.	Description from JCOSS INPUT SUMMARY	Total Utility	Allocator	Allocator %	ND
					PJB Schedule 8 Reference
	PRODUCTION				
1	BASE DEMAND	11,613	E1	39.730897%	4,614
2	PEAK DEMAND	5,754	D1	41.654420%	2,397
3	TOTAL PRODUCTION EXPENSE	17,367			7,011 Col (N); Line 4
4	TRANSMISSION EXPENSES	6,648	D2	41.257266%	2,743 Col (N); Line 5
	DISTRIBUTION EXPENSES				
5	PRIMARY DEMAND	3,344	D3	44.042944%	1,473
6	SECONDARY DEMAND	1,071	D4	45.998869%	493
7	PRIMARY CUSTOMER	2,285	C2	44.100046%	1,008
8	SECONDARY CUSTOMER	1,848	C3	44.114918%	815
9	STREETLIGHTING	1,213	C4	42.050308%	510
10	AREA LIGHTING	35	C5	46.540512%	16
11	METERS	2,015	C6	43.948376%	886
12	LOAD MANAGEMENT	-			
13	TOTAL DISTRIBUTION EXPENSE	11,812			5,201 Col (N); Line 6
	CUSTOMER ACCOUNTING EXPENSES				
14	METER READING	3,741	C7	42.205172%	1,579
15	OTHER	4,703	C8	44.092906%	2,074
16	TOTAL CUSTOMER ACCOUNTS	8,444			3,653 Col (N); Line 7
	CUSTOMER SERV & INFO EXP - (MN CIP)				
17	-MN	1,453	Direct	100.00%	-
18	- ND				
19	- SD				
20	- OTHER	1,455	C1	43.966840%	640
21	TOTAL CUSTOMER SERV & INFORMATION EXP	2,907			640 Col (N); Line 8
	ADMINISTRATIVE & GENERAL EXPENSES				
	SALARIES, SUPPLIES, PENSIONS & BENEFITS				
22	PRODUCTION	37,202	OXPD	40.243211%	14,971
23	TRANSMISSION	14,833	D2	41.257266%	6,120
24	DISTRIBUTION	23,373	OXD	44.029165%	10,291
25	CUSTOMER ACCOUNTS	17,776	OXC	43.256597%	7,689
26	CUSTOMER SERVICE & INFO	6,233	C1	43.966840%	2,741
		99,418			41,813 Col (N); Line 10
27	TOTAL	146,596			61,058 Col (N); Line 14
28	Income Tax Impact: ND Tax Rate from Sch C-6 is 39.23%				(23,950) Col (N); Line 19
29	Net Operating Income Impact				(37,108) Col (N); Line 21

Otter Tail Power Company
Adjustment for 2008; 2009 Wage Increase and Key Performance Plan and Management Incentive Plan

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	Description from JCOSS INPUT SUMMARY	From Functionalization						
	<u>PRODUCTION</u>			<u>Wage Incr.</u>	<u>Cell</u>	<u>KPP & Mgmt</u>	<u>Cell</u>	<u>Total</u>
1	BASE DEMAND	11,325,547	67%	530,409	R469	11,613	S469	542,022
2	PEAK DEMAND	5,611,117	33%	262,785	R470	5,754	S470	268,539
3	TOTAL PRODUCTION EXPENSE	16,936,664	100%	793,195		17,367		810,561
4	TRANSMISSION EXPENSES			303,657	R490	6,648	S490	310,306
	<u>DISTRIBUTION EXPENSES</u>							
5	PRIMARY DEMAND	4,157,949	28%	152,734	R493	3,344	S493	156,078
6	SECONDARY DEMAND	1,331,858	9%	48,923	R494	1,071	S494	49,994
7	PRIMARY CUSTOMER	2,841,193	19%	104,365	R495	2,285	S495	106,650
8	SECONDARY CUSTOMER	2,298,330	16%	84,424	R496	1,848	S496	86,273
9	STREETLIGHTING	1,508,249	10%	55,402	R497	1,213	S497	56,615
10	AREA LIGHTING	42,974	0%	1,579	R498	35	S498	1,613
11	METERS	2,505,796	17%	92,045	R499	2,015	S499	94,060
12	LOAD MANAGEMENT	0						
13	TOTAL DISTRIBUTION EXPENSE	14,686,349	100%	539,472		11,812		551,284
	<u>CUSTOMER ACCOUNTING EXPENSES</u>							
14	METER READING	4,654,956	44%	170,864	R505	3,741	S505	174,605
15	OTHER	5,852,304	56%	214,813	R506	4,703	S506	219,516
16	TOTAL CUSTOMER ACCOUNTS	10,507,260	100%	385,677		8,444		394,121
	<u>CUSTOMER SERV & INFO EXP - (MN CIP)</u>							
17	-MN	2,618,980	50%	66,345	R510	1,453	S510	67,798
18	- ND	0						
19	- SD	0						
20	- OTHER	2,622,720	50%	66,440	R513	1,455	S513	67,895
21	TOTAL CUSTOMER SERV & INFORMATION EXP	5,241,699	100%	132,785		2,907		135,692
	<u>ADMINISTRATIVE & GENERAL EXPENSES</u>							
	<u>SALARIES, SUPPLIES, PENSIONS & BENEFITS</u>							
22	PRODUCTION	8,158,582	37%	390,183	R551	37,202	S551	427,385
23	TRANSMISSION	3,122,913	15%	155,573	R552	14,833	S552	170,406
24	DISTRIBUTION	5,549,875	24%	245,142	R553	23,373	S553	268,515
25	CUSTOMER ACCOUNTS	3,967,362	18%	186,437	R554	17,776	S554	204,213
26	CUSTOMER SERVICE & INFO	1,365,305	6%	65,378	R555	6,233	S555	71,612
				1,042,712		99,418		1,142,130
	TOTAL A&G SALARIES, SUPP, PENSIONS & BENEFITS	22,164,036	100%					
27	TOTAL			3,197,498		146,596		3,344,094

Prepared By: KSem

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Otter Tail Power Company
Adjustment for Employee Performance Incentive and Management Performance Incentive

Line No.	(A) Description from JCROSS INPUT SUMMARY	(B) Amount	(C) %	(D) Mgmt Incentive	(E) KPP Average	(F) Mgmt Incentive	(G) KPP & Mgmt Incent.	(H) Total
	ADMINISTRATIVE & GENERAL EXPENSES							
	SALARIES, SUPPLIES, PENSIONS & BENEFITS							
1	PRODUCTION	8,158,582	36.81%	28,192				
2	TRANSMISSION	3,122,913	14.09%	10,791				
3	DISTRIBUTION	5,549,875	25.04%	19,178				
4	CUSTOMER ACCOUNTS	3,967,362	17.90%	13,709				
5	CUSTOMER SERVICE & INFO	1,365,305	6.16%	4,718				
6		22,164,036	100.00%	76,588				
Labor From FERC Form 1 Page 354-355								
7	Production	\$ 14,906,456	21.1%	\$ 793,195	\$ 17,367	\$ 17,367	\$ 17,367	\$ 810,561
8	Transmission	5,706,607	8.1%	303,657	6,648	6,648	6,648	310,306
9	Distribution	10,138,266	14.4%	539,472	11,812	11,812	11,812	551,284
10	Customer Accounts	7,247,999	10.3%	385,677	8,444	8,444	8,444	394,121
11	Customer Service & Information, & Sales (1)	2,495,421	3.5%	132,785	2,907	2,907	2,907	135,692
12	Administrative & General	19,595,620	27.8%	1,042,712	22,830	76,588	99,418	1,142,130
13	Total Labor Expense	\$ 60,090,369		\$ 3,197,498	\$ 70,008	\$ 76,588	\$ 146,596	\$ 3,344,094
14	Construction Labor	9,230,786	13.1%	491,184	10,754		10,754	501,938
15	Total Utility Labor	\$ 69,321,155		\$ 3,688,682	\$ 80,762	\$ 76,588	\$ 157,350	\$ 3,846,032
16	Below-the-Line Labor	1,161,698	1.6%	61,816	1,353		1,353	63,169
17	Total Otter Tail Power Labor	\$ 70,482,853	100.0%	\$3,750,497	\$ 82,116	\$ 76,588	\$ 158,704	\$ 3,909,201

Prepared By: KSem

Other Tail Power Company
Adjustment for Employee Annual Labor Increases

Line No.	(A) Group	(B) 2007 Total ⁴	(C) 2007 Total OTP Share	(D) December 2007 ⁴	(E) December 2007 OTP Share	(F) 2008 OTP base wage	(G) 2008 pay increase	(H) 2008 base + increase	(I) 2009 pay increase	(J) 2009 base + increase	(K) Adjustment
1	Nonunion (Including Management)	\$27,547,011.66		\$2,352,589.14							
2	Union	\$24,858,319.14		\$2,186,311.96							
3	Total ⁵	\$52,405,330.80		\$4,538,901.10							
4	Coyote Union	\$3,458,527.09	\$1,210,484.48	\$319,687.68	\$111,890.69	\$1,342,688.26	\$17,141.65	\$1,359,829.91	\$19,767.75	\$1,379,597.66	\$169,113.18
5	BSP Union	\$3,627,327.41	\$1,955,129.47	\$311,700.00	\$168,006.30	\$2,016,075.60	\$11,760.44	\$2,027,836.04	\$12,583.67	\$2,040,419.71	\$85,290.24
6	Other Union	\$17,772,464.64	\$1,772,464.64	\$1,554,924.28	\$1,554,924.28	\$18,659,091.36	\$108,844.70	\$18,767,936.06	\$16,463.83	\$18,884,399.89	\$1,111,935.25
7	Total Union	\$24,858,319.14	\$20,938,078.60	\$2,186,311.96	\$1,834,821.27	\$22,017,855.22	\$137,746.79	\$22,155,602.01	\$148,815.26	\$22,304,417.27	\$1,366,338.67
8	Coyote Nonunion ¹	\$1,093,799.64	\$382,829.87	\$97,298.00	\$34,054.30	\$408,651.60	\$11,064.24	\$419,715.84	\$14,659.01	\$434,374.86	\$51,544.98
9	BSP Nonunion ²	\$755,301.00	\$407,107.24	\$63,443.00	\$34,195.78	\$410,349.32	\$11,110.21	\$421,459.53	\$14,719.91	\$436,179.45	\$29,072.21
10	Other Nonunion	\$23,259,958.67	\$23,259,958.67	\$1,984,633.87	\$1,984,633.87	\$23,815,606.44	\$644,807.54	\$24,460,413.98	\$854,305.52	\$25,314,719.50	\$2,054,760.83
11	Total nonunion	\$25,109,059.31	\$24,049,895.78	\$2,145,374.87	\$2,052,883.95	\$24,634,607.36	\$666,981.99	\$25,301,589.36	\$883,684.44	\$26,185,273.80	\$2,135,378.02
12	Executive Management	\$1,405,300.26	\$1,405,300.26	\$120,278.00	\$120,278.00	\$1,443,336.00	\$54,774.60	\$1,498,110.60	\$79,718.95	\$1,577,829.56	\$172,529.33
13	Level 3.3 Managers ³	\$1,032,652.09	\$1,032,652.09	\$86,936.27	\$66,936.27	\$1,043,235.24	\$28,245.59	\$1,071,480.83	\$37,422.59	\$1,108,903.42	\$76,251.33
14	Total Management	\$2,437,952.35	\$2,437,952.35	\$207,214.27	\$207,214.27	\$2,486,571.24	\$83,020.20	\$2,569,591.44	\$117,141.54	\$2,686,732.98	\$248,780.63
15		\$52,405,330.80	\$47,425,926.73	\$4,538,901.10	\$4,094,919.49	\$49,139,033.82	\$887,748.98	\$50,026,782.80	\$1,149,641.24	\$51,176,424.05	\$3,750,497.32
											7.91%

¹ Excludes Plant Manager

² Excludes Plant Manager

³ Adjusted Plant Managers to reflect OTP share

⁴ Represents base labor.

⁵ Does not include Executives or Level 3 Managers

Check to Summary Tab
Difference

\$3,909,201.01
\$0.00

April 2007 average percentage increase for non-union employees was 3.61%. The 2008 increase will be 3.61% and the 2009 estimate is 3.5%.

September 2007 average percentage increase for Coyote Union employees was 3.5%. The 2008 increase is being negotiated. The avg of the 3 most recent yrs is 3.83% and will be used for 2008 & 2009.

November 2007 average percentage increase for BS & Other Union employees was 3.5%. The 2008 increase will be 3.5%. The Avg of the 3 most recent yrs is 3.6.7% and will be used for 2009.

The Executives 2007 average increase was 10.26%. The 2008 average increase was 5.06% and the avg of the last 5yrs is 6.58% which will be used for 2009.

The Level 3.3 Managers use the same percentages as Non-Union.

	2008	2009
	Increase	Increase
	Month of increase	Month of increase
Coyote Union	0.0383	0.0383
Other Union	0.035	0.0367
Non-union - non executive	0.0361	0.035
Executive	0.0506	0.0658

Prepared By: kSem

Otter Tail Power Company
Adjustment for Employee Performance Incentive

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Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(G)
1	5 year average 2003 - 2007							\$571,062	
2	Amount in Financial Statements/COSS for 2007							(488,946)	accrual for 2007
3	Adjustment							<u>\$82,116</u>	

Key Performance Plan/USIP/Gainshare									
Year	Eligible Earnings	Target	Target %	Maximum	Max %	Budget	Actual	Actual %	
2003	\$18,871,044	\$0	0%	\$1,132,263	6%	\$0	\$943,552	5%	
2004	\$19,029,174	\$0	0%	\$1,141,750	6%	\$0	\$475,729	2%	
2005	\$20,503,592	\$0	0%	\$1,230,216	6%	\$0	\$881,654	4%	
2006	\$21,344,027	\$0	0%	\$1,315,043	6%	\$0	\$213,440	1%	
2007	\$22,728,948	\$0	0%	\$1,400,371	6%	\$0	\$340,934	1%	
5Yr Average	\$20,495,357	\$0		\$1,243,929	6%	\$0	\$571,062	3%	

Prepared By: KSem

Otter Tail Power Company
Adjustment for Management Performance Incentive

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	(A)	(B)	(C)	(D)	(E)
Line No.					
1	5 year average 2003 - 2007				\$358,248
2	Amount in Financial Statements/COSS for 2007				<u>(281,660)</u>
3	Test Year Adjustment				<u>\$76,588</u>

Management Incentive Plan					
	Year	Budget/Target	Actual	Incentive > 25% of Base Pay	Actual less 25% cap on base pay
4	2003	\$333,742	\$472,690	\$76,312	\$396,378
5	2004	\$365,506	\$388,083	\$25,245	\$362,838
6	2005	\$395,708	\$595,368	\$116,832	\$478,536
7	2006	\$467,445	\$135,619	\$0	\$135,619
8	2007	\$657,254	\$519,679	\$101,811	\$417,868
9	5Yr Average	\$443,931	\$422,288	\$64,040	\$358,248
10					

Prepared By: KSem

ADJUSTMENT FOR AMORTIZED HOLDING COMPANY EXPENSES

		(A)	(B)	(C)	(D)	(E)
Line No.	Description	Total Utility	Allocator	Allocator %	ND	PJB Schedule 8 Reference
1	2007 Holding Company Expense Adjustment	131,708	NEPIS	42.050142%	55,383	Col (Y); Line 10
2	Income Tax Impact: ND Tax Rate from Sch C-6 is 39.23%				(21,724)	Col (Y); Line 19
3	Net Operating Income Impact				(33,659)	Col (Y); Line 21

**Otter Tail Power Company
Holding Company Adjustment Calculation**

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Holding Company Expense Amortization

Line No.	(A) Description	(B) Amount	(C) Entry Location
1	Total Expenses to Form Holding Company (After Tax)	\$1,100,000	
2	Gross Conversion Factor	<u>1.645413</u>	
3	Total Holding Company Expenses (Before Tax)	\$1,809,954	
4	OTP Corporate Allocation %	36.4% (1)	
5	Estimated holding company expenses (Line 9 * Line 10)	<u><u>\$658,540</u></u>	
6	Five Year amortization	\$131,708	T561

(1) Line 16(A) from Page 2 of 2 of W/P ND TY-13.

Prepared By: KSem

Otter Tail Power Company
Holding Company Adjustment Calculation

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Computation of Allocation Factors for 2008

	(A)	(B)	(C)
General Allocation Factor			
Line No.	REVENUES	2007	
1	Electric Retail Revenue	276,894	
2	Electric Wholes Revenue	20,345	
3	Other Operating Revenues	20,625	
4	Non-Asset Based Power Pool Sales	62,214	
5	Total Electric Revenues	380,078	
6	Total Consolidated Revenues continuing operations	1,295,806	
7	Ratio	29%	29%
Revenue Ratio			
TOTAL ASSETS			
8	Assets - Electric Operations	813,565	
9	Consolidated Assets	1,454,754	
10	Asset Ratio	56%	56%
TOTAL LABOR DOLLARS			
11	Labor Dollars - Electric Operations	61,773	
12	Consolidated Labor Dollars	258,497	
13	Labor Dollars - Ratio	24%	24%
14	2008 General Allocation Factor		36.4%

ADJUSTMENT FOR STORM REPAIR/PROPERTY INSURANCE EXPENSE

		(A)	(B)	(C)	(D)	(E)
Line No.	Description	Total Utility	Allocator	Allocator %	ND	PJB Schedule 8 Reference
1	2007 Storm Repair/Property Insurance Adjustment	285,354	NEPIS	42.050142%	119,992	Col (X); Line 10
2	Income Tax Impact: ND Tax Rate from Sch C-6 is 39.23%				<u>(47,067)</u>	Col (X); Line 19
3	Net Operating Income Impact				<u><u>(72,925)</u></u>	Col (X); Line 21

**Otter Tail Power Company
Test Year Adjustment
Storm Repair/Property Insurance Expense
2003 - 2007**

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Line No.		(A) 5 - Year Average	(B) 2007	(C) 2006	(D) 2005	(E) 2004	(F) 2003
1	Storm Repair/Property Insurance Costs Incurred	1,259,871	974,518	864,416	2,542,064	802,829	1,115,529
2	Adjustment to 2007 account 924 (A) - (B)	<u>285,354</u>	Enter in CELL V562 test year adjustments tab				

Note: The amount listed for 2007 above includes an adjustment made by Accounting to transfer costs related to insurance policies from FERC 924, Property Insurance to FERC 925, Injuries and Damages. The costs were for insurance policies that were not property related policies. The reclassification of the insurance policies to the correct FERC account was discovered in 2007 and in order to calculate an accurate adjustment using a five year average for comparative purposes the above amounts listed for the respective 2003 – 2006 years have been adjusted to reflect the amounts that should have been expensed into FERC 924. The same procedure will be used in calculating an accurate 5 year average for FERC 925 with the net result being no increase or decrease in actual expenses incurred from 2003 – 2006. The table below shows the actual amounts expensed in FERC 924 & 925 as well as the amounts that should have been expensed in each account for the years 2003 – 2007.

Year	FERC 924 - Property Insurance			FERC 925 - Injuries and Damages		
	Actual Amount Expensed	Correct Amount	Difference	Actual Amount Expensed	Correct Amount	Difference
2003	2,266,231	1,115,529	(1,150,702)	703,919	1,854,621	1,150,702
2004	1,735,579	802,829	(932,750)	796,363	1,729,113	932,750
2005	3,718,965	2,542,064	(1,176,901)	409,594	1,586,495	1,176,901
2006	2,079,320	864,416	(1,214,904)	492,380	1,707,284	1,214,904
2007	974,518	974,518	0	1,646,497	1,646,497	0
			(4,475,257)			4,475,257

Prepared By: KSem

ADJUSTMENT FOR ASSET-BASED MARGINS

		(A)	(B)	(C)	(D)	(E)
Line No.	Description	Total Utility	Allocator	Allocator %	ND	PJB Schedule 8 Reference
1	Asset-Based Revenue Added	609,734	E2	41.017975%	250,101	Col (E); Line 2
2	Asset-Based Expense Added	<u>1,411,060</u>	E2	41.017975%	<u>578,788</u>	Col (E); Line 4
3	Net Margin	<u>(801,326)</u>			<u>(328,687)</u>	Col (E); Line 15
4	Income Tax Impact: ND Tax Rate from Sch C-6 is 39.23%				(128,928)	Col (E); Line 19
5	Net Operating Income Impact				<u><u>(199,760)</u></u>	Col (E); Line 21

Otter Tail Power Company
Asset-Based Wholesale Margins Adjustment

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Line No.		(A)	(B)	(C)	(D)	(E)	(F)
	<u>Asset-based</u>	5 Yr Average	2007 Actual	2006 Actual	2005 Actual	2004 Actual	2003 Actual
1	Revenue in COSS (F/S)	20,743,342	20,133,608	22,926,814	24,604,889	17,794,656	18,256,744
2	Expense (adj to PS margin)	10,667,005	9,255,946	11,880,659	13,033,473	9,468,229	9,696,720
3	Margin	10,076,337	10,877,662	11,046,155	11,571,416	8,326,427	8,560,024
4	Net Adjustment	<u>(801,326)</u>					
Adjustment Detail		Cell Reference					
5	Revenue in COSS (F/S)	609,734	Y406				
6	Expense (adj to PS margin)	1,411,060	Y471				
7	Margin	(801,326)					

Prepared By: KSem

ADJUSTMENT FOR WHOLESALE MARGINS NON-ASSET BASED EXPENSE

		(A)	(B)	(C)	(D)	(E)
Line No.	Description	Total Utility	Allocator	Allocator %	ND	PJB Schedule 8 Reference
	Production Expenses					
1	Base Adjustment	1,117,334	E1	39.730897%	443,927	
2	Peak Adjustment	<u>553,623</u>	D1	41.654420%	<u>230,608</u>	
3	TOTAL Production Expense Adjustment	<u>1,670,957</u>			<u>674,535</u>	Col (P); Line 4
	Adminstration and General					
4	PRODUCTION	48	OXPD	40.243211%	19	
5	TRANSMISSION	18	D2	41.257266%	7	
6	DISTRIBUTION	32	OXD	44.029165%	14	
7	CUSTOMER ACCOUNTS	23	OXC	43.256597%	10	
8	CUSTOMER SERVICE & INFO	<u>8</u>	C1	43.966840%	<u>4</u>	
		129			<u>54</u>	Col (P); Line 10
9	Total Adjustment	1,671,086			674,590	Col (P); Line 14
10	Income Tax Impact: ND Tax Rate from Sch C-6 is 39.23%				<u>(264,608)</u>	Col (P); Line 19
11	Net Operating Income Impact				<u>(409,982)</u>	Col (P); Line 21

Otter Tail Power Company
Minnesota, North Dakota and South Dakota
Power Services FBO and Buy/Resell Expense Adjustment
Actual 12 months ending December 31, 2007

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.		Input Summary location	virtual Expense Adjustment	Buy/Resell Adjustment	2007 Total Non-Asset Wholesale Expense Adjustment to Input Summary	2007 INPUT SUMMARY Amount is shown below; slightly different from (E)	Cell Reference
1	Production expense adjustment (506 and 556)						
2	Base Adjustment (1)	Excel cell # AA469	(\$262,246)	(\$855,088)	(\$1,117,334)	\$1,117,334	Z469
3	Peak Adjustment (1)	Excel cell # AA470	(\$129,939)	(\$423,684)	(\$553,623)	\$553,623	Z470
4	Total 506 and 556 production adjustment		(\$392,186)	(\$1,278,771)	(\$1,670,957)	\$1,670,957	
5							
6							
7							
8							
9							
10	Transmission Expense adjustment (561)		\$0	\$0	\$0	\$0	
11							
12	A & G Expense Adjustment (920, 921 and 926)		Salaries, Supplies, Pension & Benefits				
13	PRODUCTION	Excel cell # AA551	(\$11)	(\$36)	(\$48)	\$48	Z551
14	TRANSMISSION (2)	Excel cell # AA552	(\$4)	(\$14)	(\$18)	\$18	Z552
15	DISTRIBUTION (2)	Excel cell #AA553	(\$8)	(\$25)	(\$32)	\$32	Z553
16	CUSTOMER ACCOUNTS (2)	Excel cell # AA554	(\$5)	(\$18)	(\$23)	\$23	Z554
17	CUSTOMER SERVICE & INFO (2)	Excel cell # AA555	(\$2)	(\$6)	(\$8)	\$8	Z555
18	Total A & G Expense Adjustment (920, 921 and 926)		(\$30)	(\$99)	(\$129)	\$129	
19							
20	A & G Expense Adjustment (930, 935)						
21	GENERAL ADVERTISING	Excel cell # AA571	\$0	\$0	\$0	\$0	
22	MISC, RENTS, MAINTENANCE	Excel cell # AA572	\$0	\$0	\$0	\$0	
23			\$0	\$0	\$0	\$0	
24							
25	Total A & G Expense Adjustment		(\$392,216)	(\$1,278,870)	(\$1,671,087)	\$1,671,086	

(1) BASE/PEAK SPLIT				
JANUARY	2007	Actual	BASE	PEAK
			62.09%	37.91%

(Ratios come from C-1)

(2) LABOR RATIOS:			PRODUCTION	TRANSMISSION	DISTRIBUTION	ACCOUNTING	SERVICE
(Ratios come from C-2)	2007	Actual	37.42%	14.92%	23.51%	17.88%	6.27%

Prepared By: KSem

ADJUSTMENT FOR PROJECTED ENERGY EFFICIENCY PROGRAMS RELATED TO BIG STONE II PRUDENCE ORDER

		(A)	(B)	(C)	(D)	(E)
Line No.	Description	Total Utility	Allocator	Allocator %	ND	PJB Schedule 8 Reference
1	CIP Expense Adjustment	1,000,000	Direct	100.00%	1,000,000	Col (R); Line 2
2	Income Tax Impact: ND Tax Rate from Sch C-6 is 39.23%				<u>(392,250)</u>	Col (R); Line 19
3	Net Operating Income Impact				<u>(607,750)</u>	Col (R); Line 21

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
North Dakota CIP Adjustment Related to Big Stone II Prudence Order

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	(A)	(B)	(C)	(D)	(E)
Line No.	Projected CIP Expense Related to Big Stone II Prudence Order	Allocation Factor	Allocation Percentage	Test Year Adjustment	Cell Reference
1 CIP Expense Adjustment	1,000,000	Directly Assigned	100.00%	1,000,000	AA511

Prepared By: KSem

ADJUSTMENT FOR CHARITABLE CONTRIBUTIONS

		(A)	(B)	(C)	(D)	(E)
Line No.	Description	Total Utility	Allocator	Allocator %	ND	PJB Schedule 8 Reference
1	Charitable Contributions	114,816	Direct	100.000000%	114,816	Col (T); Line 11
4	Income Tax Impact: ND Tax Rate from Sch C-6 is 39.23%				(45,037)	Col (T); Line 19
5	Net Operating Income Impact				<u>(69,779)</u>	Col (T); Line 21

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Otter Tail Power Company Charitable Contributions Actual 12 Months Ending 12/31/07

Line No.	(A) Account 426.1/5371 Donations:	(B)	(C) Cell Reference
1	North Dakota	229,632 (1)	
2	Proposed Allowable Portion of North Dakota Contributions (50%)	114,816	AB578
3	(1) 2007 ND Donations List found in Miscellaneous Workpaper folder.		

ADJUSTMENT FOR PROJECTED INCREMENTAL COST OF EXTENDED BIG STONE OUTAGE

		(A)	(B)	(C)	(D)	(E)
Line No.	Description	Total Utility	Allocator	Allocator %	ND	PJB Schedule 8 Reference
1	Purchased Power Reduction	(7,596,764)	E2	38.830005%	(2,949,824)	Col (Q); Line 4
2	Income Tax Impact: ND Tax Rate from Sch C-6 is 39.23%				<u>1,157,068</u>	Col (Q); Line 19
3	Net Operating Income Impact				<u><u>1,792,756</u></u>	Col (Q); Line 21

Otter Tail Power Company
Big Stone Outage Adjustment
2007 Unit Outages and Cost Deviations
December 2007

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	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
Line No.	Unit	Type of Plant	Outage Category	Reason for Outage	Date	Duration (Days)	Total Outage MWh	Outage MWh Replaced by Purchases	Total Purchase Cost	Average Purchase Cost	Unit Increm. Cost	Change in Energy Costs Due to Outages
1	Big Stone	Steam	Forced	FD fan vibration	12/29/07 HE 5 to 12/31/07 HE 1	1.9	11,306	9,374	\$353,787	\$37.74	\$13.18	\$230,242
2	Hoot Lake 2	Steam	Forced	Ice build up by FD fan	12/26/07 HE 14 to 12/28/07 HE 1	1.5	1,872	1,505	\$71,151	\$47.29	\$23.94	\$35,131
3	Hoot Lake 3	Steam	Forced				0					
4	Coyote	Steam	Forced			0						
5	Forced Outages					3.4	13,178	10,879	\$424,938			\$265,373
6	Big Stone	Steam	Scheduled	Major Overhaul	12/01/07 HE 1 to 12/24/07 HE 10	23.4	139,243	133,376	\$9,354,657	\$70.14	\$13.18	\$7,596,764
7	Hoot Lake 2	Steam				0	0					
8	Hoot Lake 3	Steam				0	0					
9	Coyote	Steam	Scheduled	Boiler Wash Outage	12/14/07 HE 1 10 12/17/07 HE 4	3.2	10,967	10,853	\$686,808	\$63.28	\$12.75	\$548,435
10	Scheduled Outages					26.6	150,210	144,229	\$10,041,465			\$8,145,199
11	Total					30	163,388	155,108	\$10,466,403			\$8,410,572

12 (1) Outages of 24 consecutive hours with 0 generation are included
13 (2) Outage MWh are estimated as follows: Unit Dispatch Max Values x 24 hours x Number of outage days

14	Total Replacement Purchase Cost	\$10,466,403
15	Total Replacement Purchase MWh	155,108
16	Average Cost	\$67.48

17	Adjustment	Cell
		Reference
	(\$7,596,764)	AC481

CHANGE IN REVENUE FOR INTER-YEAR BILLING ADJUSTMENTS

		(A)	(B)	(C)	(D)	(E)
Line No.	Description	Total Utility	Allocator	Allocator %	ND	PJB Schedule 8 Reference
1	Increase in Sales Revenue - ND	309,796	Direct	100.00%	309,796	Col (D); Line 1
2	Increase in Sales Revenue - SD	<u>(13,977)</u>	N/A	0.00%	<u>0</u>	
3	Total Increase in Revenue	<u><u>295,819</u></u>			309,796	
4	Income Tax Impact: ND Tax Rate from Sch C-6 is 39.23%				<u>121,518</u>	Col (D); Line 19
5	Net Operating Income Impact				<u><u>188,279</u></u>	Col (D); Line 21

Otter Tail Power Company
Adjustment to Revenue for Inter-Year Billing Adjustments

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Line No.	Class - NORTH DAKOTA	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			Class #	KWH CISA 2007	Revenue 2007	COE	CISA (D) + (E)	COSS (W/P B-1)	Customer Class Diff (F)-(G)	Cell Reference	% diff	KWH COSS 2007	Diff (C)-(J)	% diff
1	Residential		100	453,764,020	\$30,536,642.37	\$5,759,861.90	\$36,296,504	\$ 36,265,250	\$31,253.85	H846	0.09%	453,773,430	(9,410)	0.00%
2	Farms		101	23,562,531	\$1,336,021.21	\$251,815.80	\$1,587,837	\$ 1,590,979	(\$3,141.52)	H847	-0.20%	23,613,952	(51,421)	-0.22%
3	General Service		102	417,240,559	\$28,668,771.78	\$5,178,004.15	\$33,846,776	\$ 33,768,335	\$78,440.49	H848	0.23%	417,178,604	61,955	0.01%
4	Large General Service		103	456,708,700	\$21,468,525.26	\$5,527,862.27	\$26,996,388	\$ 26,783,847	\$212,540.11	H849	0.79%	456,145,640	563,060	0.12%
5	Irrigation		104	656,682	\$34,612.27	\$10,959.90	\$45,572	\$ 45,674	(\$102.31)	H850	-0.22%	659,077	(2,395)	-0.36%
6	Area and Street Lighting		105	22,847,012	\$2,091,625.97	(\$1.26)	\$2,091,525	\$ 2,091,712	(\$87.60)	H851	0.00%	22,848,389	(1,377)	-0.01%
7	OPA		106	17,001,233	\$729,724.88	\$228,167.56	\$957,892	\$ 961,697	(\$3,804.69)	H852	-0.40%	17,002,170	(937)	-0.01%
8	Water Heating		107	19,786,036	\$915,686.73	\$258,243.70	\$1,173,930	\$ 1,177,185	(\$3,254.42)	H853	-0.28%	19,848,693	(62,657)	-0.32%
9	Service Interrupt		108	162,382,956	\$4,734,907.45	\$337.19	\$4,735,245	\$ 4,737,220	(\$1,974.90)	H854	-0.04%	162,511,270	(128,314)	-0.08%
10	Service Deferred		109	19,241,383	\$668,507.97	\$172,649.91	\$841,158	\$ 841,231	(\$72.89)	H855	-0.01%	19,239,254	2,129	0.01%
11				1,593,191,112	\$91,185,025.89	\$17,387,901.12	\$108,572,927	\$108,263,131	\$309,796.12	AD389	0.29%	1,592,820,479	370,633	0.02%

Note: The Customer Class amounts listed should be entered on the Input Summary Tab labeled "ND Input". The overall totals should be entered on the tab labeled "Test Year Adjustment Details"

Prepared By: PBeithon

ADJUSTMENT FOR MISO SCHEDULE 16 & 17 CHARGES

Summary of Allocated ND Schedule 16 & 17 Adjustments for Revenue Increase and Annualized Expense

		(A)	(B)	(C)	(D)	(E)
Line No.	Description	Total Utility	Allocator	Allocator %	ND	PJB Schedule 8 Reference
1	Total Revenue Increased for Eliminating Schedule 16 & 17 Costs & Refunded Amount		Directly Assigned	100.00%	644,731	Col (G); Line 1
2	Jan '07 - Dec '07 Schedule 16 & 17 Costs Incurred & Deferred	626,530	E2	41.017975%	256,990	Col (G); Line 4
3	Total				387,741	Col (G); Line 15
4	Income Tax Impact: ND Tax Rate from Sch C-6 is	39.23%			152,092	Col (G); Line 19
5	Net Operating Income Impact				235,650	Col (G); Line 21

ADJUSTMENT FOR AMORTIZATION OF DEFERRED MISO SCHEDULE 16 & 17 COSTS

		(A)	(B)	(C)	(D)	(E)
Line No.	Description	Total Utility	Allocator	Allocator %	ND	PJB Schedule 8 Reference
1	Test Year Schedule 16 & 17 Amortization	753,376	E2	41.017975%	309,019	Col (F); Line 4
2	Income Tax Impact: ND Tax Rate from Sch C: 39.23%				<u>(121,213)</u>	Col (F): Line 19
3	Net Operating Income Impact				<u>(187,807)</u>	Col (F); Line 21

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Otter Tail Power Company
Calculation of Revenue Reduction for Eliminating MISO Schedule 16 & 17 Charges from FCA

Line No.	Month	(A)	(B)	(C)	(D)	(E)	(F)					(G)	(H)	(I)	(J)	(K)
			COE RATE AS ORIGINALLY FILED (1)	COE RATE AFTER SCHEDULE 16 & 17 CHARGES ELIMINATED (2)	COE RATE REDUCTION	ND KWH SALES SUBJECT TO COE (3)	TOTAL REVENUE REDUCTION/(INCREASE)					CLASS	KWH (6)	ALLOCATION %	REVENUE REDUCTION ADJUSTMENT (5)	Input Cell #
1	Jan-07		0.01160	0.01140	0.00020	132,737,508	26,548									
2	Feb-07		0.01380	0.01350	0.00030	143,497,138	43,049					1	RES	32.31%	(208,314)	K 846
3	Mar-07		0.01390	0.01370	0.00020	124,320,711	24,864					2	FARM	1.68%	(10,855)	K 847
4	Apr-07		0.01810	0.01790	0.00020	111,560,902	22,312					3	Small Commercial	15.53%	(100,098)	K 848
5	May-07		0.01980	0.01960	0.00020	101,495,671	20,299					4	Large Commercial	46.75%	(301,386)	K 849
6	Jun-07		0.02160	0.02150	0.00010	98,898,648	9,890					5	Irrigation	0.05%	(303)	K 850
7	Jul-07		0.01990	0.01980	0.00010	109,963,557	10,996					6	Lighting	0.00%	0	K 851
8	Aug-07		0.01640	0.01620	0.00020	119,317,333	23,863					7	OPA	1.21%	(7,817)	K 852
9	Sep-07		0.01050	0.01040	0.00010	108,627,016	10,863					8	Water Heating	1.42%	(9,126)	K 853
10	Oct-07		0.00260	0.00520	(0.00260)	102,417,088	(266,284)					9	Interruptible	0.00%	0	K 854
11	Nov-07		0.00260	0.00520	(0.00260)	120,394,960	(313,027)					10	Deferred	1.06%	(6,833)	K 855
12	Dec-07		0.00360	0.00560	(0.00200)	129,052,241	(258,104)									
13	Totals					1,402,282,773	(644,731)						1,402,282,773	100.00%	(644,731)	AF 389

14 (1) Per "Cost of Energy for ND" File located in the 2007 Test Year Folder for ND Rate Case.

15 (2) Per "Cost of Energy for ND After Eliminating 16 & 17 Costs" File located in the 2007 Test Year Folder for ND Rate Case

16 (3) Per CIS330 report for 2007.

17 (4) Cell reference is for tab titled "Test Year Adjustment Details". All other (K) cell references are for tab titled "MN Input".

18 (5) All adjustments are entered on the Test Year Input Summary as a positive amount.

19 (6) Per "CIS330a Revenue Report 2007" file located in Miscellaneous Workpaper folder.

Prepared By: KSem

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Offer Tail Power Company
MISO Schedule 16 & 17 Test Year Adjustment Leadsheet

Cost Recovery calculation - 3-Year Amortization		(A)	(C)	(D)	(E)
Line No.	Description	Amount	Annual Amortization	Adjustment Amount	Cell
1	Apr '05 - Dec '05 Schedule 16 & 17 Costs Incurred & Deferred	\$457,994			
2	Jan '06 - Dec '06 Schedule 16 & 17 Costs Incurred & Deferred	617,728			
3	Jan '07 - Dec '07 Schedule 16 & 17 Costs Incurred & Deferred	<u>626,530</u>		626,530 (1)	AF481
4	Total 2005-2007 Schedule 16 & 17 Charges	<u>1,702,252</u>			
5	Jan '08 - June '08 Schedule 16 & 17 Costs Incurred & Deferred	367,602			
6	July '08 - Oct '08 Schedule 16 & 17 Costs Projected to be Incurred & deferred	<u>190,272</u>			
7	Total Projected 2008 Schedule 16 & 17 Costs to be Incurred & Deferred Prior to the Rate Case Filing	<u>557,875</u>			
8	Total Apr' 05 - Oct '08 Schedule 16 & 17 Costs to be Deferred and Amortized	<u>\$2,260,127</u>	\$753,376	\$753,376 (2)	AE481
9	Test Year Adjustment				

- (1) Adjustment for 2007 actual expenses that have been deferred; Adjustment is needed to normalize the current year.
(2) Adjustment is to record the annual amortization of prior deferred costs that have not been recovered.

Source: See "Monthly Costs" Tab for further detail.

Prepared By: KSem

MISO DAY 2 COSTS. The adoption of these terms by the Commission was requested by Mr. Larry Schedin, witness on behalf of the Large Industrial Energy Group, and supported in part by the Mr. Peter Beithon, witness on behalf of Otter Tail.

PROCEDURAL HISTORY

On March 1, 2005, Otter Tail filed an Application for revisions in its Fuel Clause Adjustment ("FCA") tariff to reflect new accounting procedures effective with the April 1, 2005 implementation of a new Midwest ISO ("MISO") Day 2 regional wholesale electric energy market. On April 6, 2005 the Commission issued its Interim Order temporarily authorizing new accounting procedures for interim fuel clause recovery of the net costs of energy purchased through the new market subject to refund with interest in the event the Commission ultimately ordered a different or modified accounting treatment that results in lower charges. On January 24, 2007 the Commission granted intervention to the Large Industrial Energy Group. On April 20, 2007 the Large Industrial Energy Group filed Direct Testimony, and on May 14, 2007, Otter Tail filed Reply Testimony.

Terms of Settlement Agreement

The Parties agree to, and recommend the Commission approve the following provisions.

1. Except as regards Schedules 16 and 17¹ costs, discussed below, Otter Tail may recover the charges imposed by the Midwest Independent Transmission System Operator, Inc., for MISO Day 2 operations (offset by revenues from Day 2 operations via net accounting) through the calculation of Otter Tail's FCA. from the period April 1, 2005 through a period of at least three years after the date of the Commission Order accepting the Settlement Agreement.
2. Otter Tail may use deferred accounting for MISO Schedule 16 and 17 costs incurred since April 1, 2005. Otter Tail may continue deferring Schedule 16 and 17 costs without interest until the earlier of Otter Tail's next electric rate case or March 1, 2009. By

¹ See Appendix A hereto for a description of MISO schedules 16 and 17.

March 1, 2009, Otter Tail shall begin amortizing the balance of the deferred Day 2 costs through March 1, 2012, unless and until Otter Tail has a rate case addressing its proposal for recovering the balance.

3. In its next rate case, Otter Tail may seek to recover Schedule 16 and 17 costs at an appropriate level of base rate recovery. Otter Tail may not increase rates to recover MISO administrative costs unless the costs were prudently incurred, reasonable, resulted in benefits justifying recovery and not already recovered through other rates. However, Otter Tail may seek to recover Schedule 16 and 17 costs and associated amortizations through interim rates pending the resolution of a rate case, subject to final Commission approval.
4. Otter Tail shall use reasonable efforts to refund through the FCA all Schedule 16 and 17 costs previously recovered through the FCA by February 1, 2008. This refund amount shall be included in the deferral balance. For purposes of OTP's fuel clause true-up calculations, the refunds for Schedule 16 and 17 costs shall be reflected in the calculations for the periods during which they are made. The refund of Schedule 16 and 17 costs shall not affect prior true-ups.
5. Virtual Energy transactions in the Day 2 market are subject to the following conditions:
 - A. Otter Tail may use virtual energy transactions to take positions 1) from the Day-Ahead to the Real-Time market or 2) from the Real-Time to the Day-Ahead market, but only as a strategy to reduce risk and/or minimize costs assigned to retail customers. Otter Tail shall not engage in virtual energy transactions that affect the FCA for speculative purposes.
 - B. Virtual energy transactions that affect the FCA shall be summarized on a monthly basis and be included as a component of the monthly fuel clause reports to the Commission.

- C. Otter Tail shall restrict the use of virtual transactions that affect the FCA to 10% of total MWh subject to the FCA on a monthly basis with the understanding that the 10% threshold may be exceeded in any particular month, subject to the requirement that Otter Tail must explain the reasonableness of any deviation above the 10% threshold in its monthly fuel clause reporting. The 10% threshold does not apply to non-FCA virtual energy transactions (e.g. for non-asset based trading activities). The Commission may review and reset the 10% threshold as circumstances warrant.
- 6. Otter Tail shall adopt the following accounting practices:
 - A. Recording each transaction to a separate sub-account of Accounts 447 and 555.
 - B. Recording to Account 555 on an aggregated basis any revenues and costs linked to Day 2 LMP, including generation offers to the market and load purchases used to serve native load customers, marginal loss compensations, and marginal loss credits, if allowed through the fuel clause.
 - C. Using net accounting for purchases and sales for owned generation facilities.
 - D. Continuing to use Accounts 151 and 501 to record the fuel costs related to generation plants serving native load, the same way they are accounted for today.
 - E. Continuing to use Account 447 to reflect the true costs of off-system wholesale sales, including related MISO costs.
 - F. Tracking in a separate sub-account each MISO charge and revenue.
 - G. Allocating all MISO Day 2 charges pursuant to the Minnesota Joint Report's Exhibit C, attached in revised form.

Otter Tail Power Company
Schedule 16 & 17 Monthly Charges

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Line No.	(A) Month costs incurred	(B) 2005	(C) 2006	(D) 2007	(E) 2008	(F) Monthly Averages
1	January		46,607.45	65,146.15	67,373.25	59,708.95
2	February		65,405.70	67,671.76	91,494.39	74,857.28
3	March		51,238.85	36,739.64	55,055.74	47,678.08
4	April	\$62,891.60	48,254.54	53,606.79	53,876.51	54,657.36
5	May	59,427.19	45,691.59	54,341.13	43,809.48	50,817.35
6	June	48,488.56	32,970.18	55,143.10	55,992.85	48,148.67
7	July	61,656.27	49,662.35	57,186.88		56,168.50
8	August	64,611.75	49,968.24	51,050.21		55,210.07
9	September	36,717.39	38,545.50	33,879.58		36,380.82
10	October	28,538.94	49,934.30	49,065.75		42,513.00
11	November	46,903.67	71,563.87	41,335.26		53,267.60
12	December	43,658.51	67,885.20	61,363.73		57,635.81
13	Adj Apr-Dec	5,100.36				
14	Total	\$457,994.24	\$617,727.77	\$626,529.98	\$367,602.22	\$637,043.49

Prepared By: KSem

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Offer Tail Power Company
Calculation of the impact of the change in allocation factors due to the addition of a large load in North Dakota

Line No.	(A)	(B)		(C)		(D)		(E)		(F)		(G)	(H)
		With Large Load - modified allocation factors		Without Large Load - allocation factors		Impact of Change in Allocation Factors							
		Total Company	ND	Total Company	ND	Total Company	ND	Total Company	ND	Total Company	ND		
1	ELECTRIC PLANT IN SERVICE	946,761,213	396,566,104	946,761,213	382,741,667	-	13,824,437	-	13,824,437	-	13,824,437		
2	ACCUMULATED DEPRECIATION	(453,609,720)	(188,390,753)	(453,609,720)	(188,378,692)	-	(12,061)	-	(12,061)	-	(12,061)		
3	NET PLANT EXCLUDING BIG STONE PLANT CAPITALIZED	493,151,493	208,175,351	493,151,493	194,362,975	-	13,812,376	-	13,812,376	-	13,812,376		
4	NET CAPITALIZED ITEMS - BIG STONE PLANT	129,351	118,635	129,351	118,635	-	-	-	-	-	-		
5	NET ELECTRIC PLANT IN SERVICE	493,280,843	208,293,986	493,280,843	194,481,610	-	13,812,376	-	13,812,376	-	13,812,376		
6	PLANT HELD FOR FUTURE USE	29,656	12,871	29,656	12,674	-	197	-	197	-	197		
7	CONSTRUCTION WORK IN PROGRESS	26,037,862	2,248,082	26,037,862	2,215,710	-	32,372	-	32,372	-	32,372		
8	MATERIALS AND SUPPLIES	13,498,511	5,722,737	13,498,511	5,554,248	-	168,489	-	168,489	-	168,489		
9	FUEL STOCKS	7,638,969	3,072,173	7,638,969	2,887,084	-	185,089	-	185,089	-	185,089		
10	PREPAYMENTS	(35,518,043)	(14,997,937)	(35,518,043)	(14,003,394)	-	(994,542)	-	(994,542)	-	(994,542)		
11	CUSTOMER ADVANCES	(129,099)	(54,513)	(129,099)	(50,899)	-	(3,615)	-	(3,615)	-	(3,615)		
12	CASH WORKING CAPITAL	10,253,766	4,945,717	10,112,418	4,811,395	141,349	134,322	141,349	134,322	141,349	134,322		
13	ACCUMULATED DEFERRED INCOME TAXES	(79,531,881)	(32,682,330)	(79,531,881)	(30,837,636)	-	(1,844,693)	-	(1,844,693)	-	(1,844,693)		
14	UNAMORTIZED BALANCE - SPIRITWOOD	-	-	-	-	-	-	-	-	-	-		
15	UNAMORTIZED RATE CASE EXPENSE	-	-	-	-	-	-	-	-	-	-		
16	TOTAL AVERAGE RATE BASE	435,560,585	176,560,787	435,419,236	165,070,791	141,349	11,489,996	141,349	11,489,996	141,349	11,489,996		

Col (G); Line 28

Otter Tail Power Company
Calculation of the impact of the change in allocation factors due to the addition of a large load in North Dakota

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)
PLANT IN SERVICE		With Large Load - modified allocation factors		Without Large Load - allocation factors		Impact of Change in Allocation Factors		
Line No.		Total Company	ND	Total Company	ND	Total Company	ND	Exhibit_(KAS-1), Schedule 4 Reference
1	PRODUCTION PLANT	253,626,490	100,768,079	253,626,490	94,355,623	-	6,412,457	
2	A/C 101 & 106 - BASE DEMAND	111,695,887	46,526,274	111,695,887	44,167,774	-	-	
3	PEAK DEMAND	-	-	-	-	-	-	
	BASE ENERGY	-	-	-	-	-	-	
4	SUBTOTAL A/C 101 & 106	365,322,377	147,294,353	365,322,377	138,523,397	-	8,770,957	
5	A/C 114 - BASE DEMAND	1,101,931	437,807	1,101,931	409,947	-	27,860	
6	PEAK DEMAND	486,324	202,575	486,324	192,306	-	10,269	
7	BASE ENERGY	-	-	-	-	-	-	
8	SUBTOTAL A/C 114	1,588,255	640,382	1,588,255	602,253	-	38,129	
9	TOTAL PRODUCTION PLANT	366,910,631	147,934,736	366,910,631	139,125,650	-	8,809,086	Col (G); Line 1
10	TRANSMISSION PLANT							
11	A/C 101 & 106	190,602,711	78,637,467	190,602,711	74,622,552	-	4,014,915	
12	A/C 114	58,287	24,048	58,287	22,820	-	1,228	
13	TOTAL TRANSMISSION PLANT	190,660,998	78,661,515	190,660,998	74,645,372	-	4,016,143	Col (G); Line 2
14	DISTRIBUTION PLANT							
15	PRIMARY DEMAND	100,970,644	44,470,444	100,970,644	44,354,597	-	115,847	
16	SECONDARY DEMAND	51,591,927	23,731,703	51,591,927	23,739,242	-	(7,539)	
17	PRIMARY CUSTOMER	58,148,137	25,643,355	58,148,137	25,643,355	-	-	
18	SECONDARY CUSTOMER	59,922,510	26,434,766	59,922,510	26,434,766	-	-	
19	STREETLIGHTING	11,989,203	5,041,497	11,989,203	5,041,497	-	-	
20	AREA LIGHTING	4,476,664	2,083,462	4,476,664	2,083,462	-	-	
21	METERS	19,597,938	8,612,975	19,597,938	8,612,975	-	-	
	LOAD MANAGEMENT	8,402,928	3,704,245	8,402,928	3,704,245	-	-	
22	TOTAL DISTRIBUTION PLANT	315,099,950	139,722,448	315,099,950	139,614,140	-	108,308	Col (G); Line 3
23	GENERAL PLANT							
24	PRODUCTION	26,059,374	10,506,882	26,059,374	9,881,227	-	625,654	
25	TRANSMISSION	10,181,778	4,200,723	10,181,778	3,986,251	-	214,472	
26	DISTRIBUTION	17,052,390	7,561,416	17,052,390	7,555,554	-	5,861	
27	CUSTOMER ACCOUNTS	12,562,370	5,434,054	12,562,370	5,434,054	-	-	
28	CUSTOMER SERVICE & INFO	4,363,674	999,969	4,363,674	999,969	-	-	
	LOAD MANAGEMENT	135,027	59,524	135,027	59,524	-	-	
29	TOTAL GENERAL PLANT	70,354,613	28,722,567	70,354,613	27,876,579	-	845,988	Col (G); Line 4
30	INTANGIBLE PLANT							
		3,735,021	1,524,838	3,735,021	1,479,926	-	44,912	Col (G); Line 5
31	TOTAL PLANT IN SERVICE	946,761,213	396,566,104	946,761,213	382,741,667	-	13,824,437	Col (G); Line 6

Offer Tail Power Company

Calculation of the impact of the change in allocation factors due to the addition of a large load in North Dakota

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Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	ACCUMULATED DEPRECIATION	With Large Load - modified allocation factors		Without Large Load - allocation factors		Impact of Change in Allocation Factors		
		Total Company	ND	Total Company	ND	Total Company	ND	Exhibit (KAS-1), Schedule 4 Reference
1	PRODUCTION PLANT							
2	BASE DEMAND	E1	(56,286,975)	(140,960,222)	(56,286,975)	-	-	
3	PEAK DEMAND	D1	(29,902,756)	(74,858,563)	(29,902,756)	-	-	
	BASE ENERGY	E1	-	-	-	-	-	
4	TOTAL PRODUCTION PLANT		(86,189,731)	(215,818,786)	(86,189,731)	-	-	
5	TRANSMISSION PLANT	D2	(30,696,441)	(76,391,323)	(30,696,441)	-	-	
6	DISTRIBUTION PLANT	P60	(59,315,268)	(131,748,913)	(59,315,268)	-	-	
7	GENERAL PLANT	P90	(11,779,824)	(28,647,675)	(11,779,824)	-	-	
8	INTANGIBLE PLANT	P90	(409,489)	(1,003,024)	(397,428)	-	(12,061)	Col (G); Line 11
9	TOTAL ACCUMULATED DEPRECIATION		(188,390,753)	(453,609,720)	(188,378,692)	-	(12,061)	
10	NET PLANT EXCLUDING BSP CAPITALIZED ITEMS		208,175,351	493,151,493	194,362,975	-	13,812,376	
11	BSP CAPITALIZED ITEMS	P10	118,635	129,351	118,635	-	-	
12	TOTAL NET PLANT IN SERVICE	NEPIS	208,293,986	493,280,843	194,481,610	-	13,812,376	
13	PLANT HELD FOR FUTURE USE							
14	PRODUCTION PLANT	P10	3,729	9,038	3,538	-	190	
15	TRANSMISSION PLANT	D2	9,142	20,618	9,135	-	7	
16	DISTRIBUTION PLANT	P60	-	-	-	-	-	
17	GENERAL PLANT	P90	-	-	-	-	-	
	INTANGIBLE PLANT	P90	-	-	-	-	-	
18	TOTAL PLANT HELD FOR FUTURE USE		12,871	29,656	12,674	-	197	Col (G); Line 21

Otter Tail Power Company
Calculation of the impact of the change in allocation factors due to the addition of a large load in North Dakota

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		With Large Load - modified allocation factors		Without Large Load - allocation factors		Impact of Change in Allocation Factors		
		Total Company	ND	Total Company	ND	Total Company	ND	
1	CONST WORK-IN-PROGRESS - MAJOR PROJECTS							Exhibit (KAS-1), Schedule 4 Reference
2	PRODUCTION PLANT		P10					
3	TRANSMISSION PLANT		D2					
4	DISTRIBUTION PLANT		P60					
5	GENERAL PLANT		P90					
6	INTANGIBLE PLANT		P90					
7	TOTAL CWIP - MAJOR PROJECTS							
8	CONST WORK-IN-PROGRESS - SHORT-TERM							
9	PRODUCTION PLANT	144,982	P10	58,455	144,982	-	3,481	
10	TRANSMISSION PLANT	574,800	D2	237,147	574,800	-	12,108	
11	DISTRIBUTION PLANT	3,202,396	P60	1,420,015	3,202,396	-	1,101	
12	GENERAL PLANT	1,304,249	P90	532,465	1,304,249	-	15,683	
13	INTANGIBLE PLANT	-	P90	-	-	-	-	
14	TOTAL CWIP - SHORT-TERM	5,226,428		2,248,082	5,226,428	-	32,372	
15	CONST WORK-IN-PROGRESS - LONG TERM							
16	PRODUCTION PLANT	13,197,861	P10	-	13,197,861	-	-	
17	TRANSMISSION PLANT	3,742,692	D2	-	3,742,692	-	-	
18	DISTRIBUTION PLANT	2,703,641	P60	-	2,703,641	-	-	
19	GENERAL PLANT	1,167,240	P90	-	1,167,240	-	-	
20	INTANGIBLE PLANT	-	P90	-	-	-	-	
21	TOTAL CWIP - LONG TERM	20,811,434		-	20,811,434	-	-	
22	TOTAL CONSTRUCTION WORK-IN-PROGRESS	26,037,862		2,248,082	26,037,862	-	32,372	Col (G); Line 22
23	MATERIALS & SUPPLIES							
24	PRODUCTION	3,772,973	P10	1,521,225	3,772,973	-	90,585	
25	TRANSMISSION	3,598,449	D2	1,484,622	3,598,449	-	75,799	
26	DISTRIBUTION	6,127,090	P60	2,716,890	6,127,090	-	2,106	
27	TOTAL MATERIALS AND SUPPLIES	13,498,511		5,722,737	13,498,511	-	168,469	Col (G); Line 23
28	FUEL STOCKS							
29	COAL STOCKS	5,708,035	E1	2,267,853	5,708,035	-	144,317	
30	FUEL OIL STOCKS	1,930,934	D1	804,319	1,930,934	-	40,772	
31	TOTAL FUEL STOCKS	7,638,969		3,072,173	7,638,969	-	185,089	Col (G); Line 24
32	PREPAYMENTS							
33	CUSTOMER ADVANCES	(35,518,043)	NEPIS	(14,997,937)	(35,518,043)	-	(994,542)	Col (G); Line 25
34	CASH WORKING CAPITAL	(129,099)	NEPIS	(54,513)	(129,099)	-	(3,615)	Col (G); Line 26
35		10,253,766	OX	4,945,717	10,112,418	141,349	134,322	Col (G); Line 27

Calculation of the change in allocation factors due to the addition of a large load in North Dakota

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)		
		(B)		(C)		(E)			(F)	
		With Large Load - modified allocation factors		Without Large Load - allocation factors		Impact of Change in Allocation Factors				
		Total Company	ND	Total Company	ND	Total Company	ND			
1	OPERATING REVENUES	268,698,170	108,472,410	268,698,170	108,472,410	-	-	Col (S); Line 2		
2	SALES OF ELECTRICITY	33,216,346	13,384,726	33,216,346	12,622,188	-	762,538			
3	OTHER OPERATING REVENUE									
3	TOTAL OPERATING REVENUE	301,914,516	121,857,136	301,914,516	121,094,598	-	762,538			
	OPERATING EXPENSES									
4	PRODUCTION EXPENSES	160,332,202	65,654,497	160,332,202	62,106,875	-	3,547,621	Col (S); Line 4		
5	TRANSMISSION EXPENSES	10,492,992	4,329,122	10,492,992	4,108,094	-	221,028	Col (S); Line 5		
6	DISTRIBUTION EXPENSES	14,686,349	6,466,277	14,686,349	6,461,701	-	4,576	Col (S); Line 6		
7	CUSTOMER ACCOUNTING EXPENSES	10,507,260	4,545,083	10,507,260	4,545,083	-	-			
8	CUSTOMER SERVICE AND INFORMATION EXPENSES	5,241,699	1,153,127	5,241,699	1,153,127	-	-			
9	SALES EXPENSES	1,121,951	628,984	1,121,951	628,984	-	-	Col (S); Line 10		
10	ADMINISTRATIVE AND GENERAL EXPENSES	31,837,814	12,721,026	31,837,814	12,293,584	-	427,442	Col (S); Line 12		
11	CHARITABLE CONTRIBUTIONS	111,967	-	111,967	-	-	-			
12	DEPRECIATION EXPENSE	24,836,391	10,162,275	24,836,391	10,157,335	-	4,940	Col (S); Line 13		
13	AMORTIZATION OF BIG STONE PLANT CAPITALIZED COSTS	-	-	-	-	-	-			
14	SPIRITWOOD AMORTIZATION	-	-	-	-	-	-			
15	GENERAL TAXES	9,411,607	3,974,168	9,411,607	3,710,634	-	263,535	Col (S); Line 14		
16	TOTAL OPERATING EXPENSES	268,580,233	109,634,559	268,580,233	105,165,417	-	4,469,142	Col (S); Line 14		
17	NET OPERATING INCOME BEFORE INCOME TAXES	33,334,283	12,222,577	33,334,283	15,929,181	-	(3,706,604)	Col (S); Line 15		
	INCOME TAX EXPENSE									
18	INVESTMENT TAX CREDIT	(1,136,657)	(476,107)	(1,136,657)	(459,510)	-	(16,597)	Col (S); Line 17		
19	DEFERRED INCOME TAXES	477,922	217,123	477,922	207,151	-	9,972	Col (S); Line 18		
20	INCOME TAXES	8,061,047	2,706,738	8,005,239	4,298,276	55,808	(1,591,538)	Col (S); Line 19		
21	TOTAL INCOME TAX EXPENSE	7,402,312	2,447,754	7,346,504	4,045,918	-	(1,598,164)	Col (S); Line 20		
22	NET OPERATING INCOME	25,931,971	9,774,823	25,987,779	11,883,263	(55,808)	(2,108,440)	Col (S); Line 21		
23	ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	2,257,062	-	2,257,062	-					
24	TOTAL AVAILABLE FOR RETURN	28,189,033	9,774,823	28,244,841	11,883,263	(55,808)	(2,108,440)			

Volume 4A – Section 2

2007 Actual Year work papers

Volume 4A – Section 2

2007 Actual Year work papers

Jurisdictional Cost of Service Study
(JCOSS)

LINE NO	ITEM	ALLOC	REFERENCE	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	RATE BASE		Page 2-1 Line 32	435,419,236	185,070,791	270,348,445	1
2	TOTAL AVAILABLE FOR RETURN		Page 7-1 Line 43	28,244,841	11,883,263	16,361,579	2
3							3
4							4
5	RATE OF RETURN EARNED			6.49%	7.20%	6.05%	5
6							6
7	RATE OF RETURN REQUESTED		Page 17-1 Line 11		8.89%		7
8							8
9	OPERATING INCOME REQUIRED				14,674,793		9
10							10
11	TOTAL AVAILABLE FOR RETURN				11,883,263		11
12							12
13	OPERATING INCOME DEFICIENCY				2,791,531		13
14							14
15	INCREMENTAL TAXES	GRCF = 1.645413			1,801,690		15
16							16
17	REVENUE INCREASE REQUIRED				4,593,221		17
18							18
19	PERCENTAGE INCREASE				4.23%		19
20							20
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OTTER TAIL POWER COMPANY
COST OF SERVICE STUDY
ACTUAL YEAR 2007 - 10 CLASSES

OTTER TAIL POWER COMPANY
COST OF SERVICE STUDY
ACTUAL YEAR 2007 - 10 CLASSES

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LINE NO	ITEM	ALLOC	REFERENCE	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	ELECTRIC PLANT IN SERVICE		Page 3-1 Line 52	946,761,213	382,741,667	564,019,546	1
2	ACCUMULATED DEPRECIATION		Page 4-12 Line 22	(453,608,720)	(188,378,692)	(265,231,028)	2
3							3
4	NET PLANT EXCLUDING BIG STONE PLANT CAPITALIZED ITEMS			493,151,493	194,362,975	298,788,518	4
5							5
6	NET CAPITALIZED ITEMS - BIG STONE PLANT			128,351	118,635	10,715	6
7	NET ELECTRIC PLANT IN SERVICE		Page 4-1 Line 28	493,280,843	194,481,610	298,799,233	7
8							8
9	PLANT HELD FOR FUTURE USE		Page 4-1 Line 47	28,656	12,674	16,982	9
10							10
11	CONSTRUCTION WORK IN PROGRESS		Page 5-1 Line 31	26,037,862	2,215,710	23,822,152	11
12							12
13	MATERIALS AND SUPPLIES		Page 5-1 Line 39	13,468,511	5,554,248	7,944,264	13
14							14
15	FUEL STOCKS		Page 5-1 Line 46	7,538,969	2,887,084	4,751,885	15
16							16
17	PREPAYMENTS		Page 5-1 Line 49	(35,518,043)	(14,003,394)	(21,514,649)	17
18							18
19	CUSTOMER ADVANCES		Page 5-1 Line 51	(128,099)	(50,899)	(78,200)	19
20							20
21	CASH WORKING CAPITAL		Page 5-1 Line 53	10,112,418	4,811,395	5,301,022	21
22							22
23	ACCUMULATED DEFERRED INCOME TAXES		Page 6-1 Line 16	(79,531,881)	(30,837,636)	(48,694,245)	23
24							24
25	UNAMORTIZED BALANCE - SPIRITWOOD		Page 6-1 Line 19	0	0	0	25
26							26
27	UNAMORTIZED RATE CASE EXPENSE		Page 6-1 Line 22	0	0	0	27
28							28
29							29
30							30
31							31
32	TOTAL AVERAGE RATE BASE			455,419,236	165,070,791	270,348,445	32
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LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	PLANT IN SERVICE					1
2	PRODUCTION PLANT					2
3	AC 101 & 106 - BASE DEMAND	E1	253,626,490	94,355,623	159,270,867	3
4	PEAK DEMAND	D1	111,695,887	44,167,774	67,528,113	4
5	BASE ENERGY	E1	0	0	0	5
6						6
7	SUBTOTAL AC 101 & 106		365,322,377	138,523,397	226,798,980	7
8						8
9	AC 114 - BASE DEMAND	E1	1,101,931	409,947	691,984	9
10	PEAK DEMAND	D1	486,324	192,306	294,017	10
11	BASE ENERGY	E1	0	0	0	11
12						12
13	SUBTOTAL AC 114		1,588,255	602,253	986,001	13
14						14
15	TOTAL PRODUCTION PLANT	P10	366,910,631	139,125,650	227,784,981	15
16						16
17						17
18	TRANSMISSION PLANT					18
19	AC 101 & 106	D2	190,602,711	74,622,552	115,980,159	19
20	AC 114	D2	56,267	22,820	33,447	20
21						21
22	TOTAL TRANSMISSION PLANT		190,660,986	74,645,372	116,015,616	22
23						23
24						24
25	DISTRIBUTION PLANT					25
26	PRIMARY DEMAND	D3	100,970,644	44,354,597	56,616,047	26
27	SECONDARY DEMAND	D4	51,991,927	23,739,282	27,832,685	27
28	PRIMARY CUSTOMER	C2	58,148,137	25,643,355	32,504,781	28
29	SECONDARY CUSTOMER	C3	59,922,510	26,434,766	33,487,744	29
30	STREET LIGHTING	C4	11,988,203	5,041,497	6,947,706	30
31	AREA LIGHTING	C5	4,476,664	2,083,462	2,393,202	31
32	METERS	C6	19,597,938	8,612,975	10,984,962	32
33	LOAD MANAGEMENT	C9	8,402,928	3,704,245	4,698,683	33
34						34
35	TOTAL DISTRIBUTION PLANT	P60	315,099,950	139,614,140	175,485,810	35
36						36
37						37
38	GENERAL PLANT					38
39	PRODUCTION	P10	26,059,374	9,881,227	16,178,147	39
40	TRANSMISSION	D2	10,181,778	3,986,251	6,195,527	40
41	DISTRIBUTION	P60	17,052,390	7,555,554	9,496,836	41
42	CUSTOMER ACCOUNTS	OXC	12,562,370	5,434,054	7,128,316	42
43	CUSTOMER SERVICE & INFO	OXI	4,383,674	959,969	3,403,705	43
44	LOAD MANAGEMENT	C9	135,027	59,524	75,503	44
45						45
46	TOTAL GENERAL PLANT	P90	70,354,613	27,876,579	42,478,034	46
47						47
48	INTANGIBLE PLANT					48
49		P90	3,735,021	1,479,926	2,255,095	49
50						50
51	TOTAL PLANT IN SERVICE	EPIS	946,761,213	382,741,667	564,019,546	51
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OTTER TAIL POWER COMPANY
COST OF SERVICE STUDY
ACTUAL YEAR 2007 - 10 CLASSES

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LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	ACCUMULATED DEPRECIATION					1
2	PRODUCTION PLANT					2
3	BASE DEMAND		(140,960,222)	(56,286,975)	(84,673,248)	3
4	PEAK DEMAND		(74,659,563)	(29,902,756)	(44,755,807)	4
5	BASE ENERGY		0	0	0	5
6						6
7	TOTAL PRODUCTION PLANT		(215,619,785)	(86,189,731)	(129,629,054)	7
8						8
9	TRANSMISSION PLANT		(76,391,323)	(30,696,441)	(45,694,882)	9
10						10
11						11
12	DISTRIBUTION PLANT		(131,749,913)	(59,315,268)	(72,433,644)	12
13						13
14						14
15	GENERAL PLANT		(28,647,675)	(11,779,824)	(16,867,851)	15
16						16
17						17
18	INTANGIBLE PLANT		(1,003,024)	(397,428)	(605,596)	18
19						19
20						20
21						21
22	TOTAL ACCUMULATED DEPRECIATION		(453,699,720)	(188,378,692)	(265,231,028)	22
23						23
24	NET PLANT EXCLUDING BSP CAPITALIZED ITEMS		493,151,493	194,362,975	298,788,518	24
25						25
26						26
27	BSP CAPITALIZED ITEMS		128,351	118,635	10,715	27
28						28
29						29
30						30
31	TOTAL NET PLANT IN SERVICE		493,280,843	194,481,610	298,799,233	31
32						32
33						33
34						34
35						35
36						36
37						37
38						38
39						39
40	PLANT HELD FOR FUTURE USE					40
41	PRODUCTION PLANT		0	0	0	41
42	TRANSMISSION PLANT		9,038	3,538	5,500	42
43	DISTRIBUTION PLANT		20,618	9,135	11,483	43
44	GENERAL PLANT		0	0	0	44
45	INTANGIBLE PLANT		0	0	0	45
46	TOTAL PLANT HELD FOR FUTURE USE		29,656	12,674	16,982	46
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LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	CONST WORK-IN-PROGRESS - MAJOR PROJECTS					1
2	PRODUCTION PLANT	P10	0	0	0	2
3	TRANSMISSION PLANT	D2	0	0	0	3
4	DISTRIBUTION PLANT	P60	0	0	0	4
5	GENERAL PLANT	P90	0	0	0	5
6	INTANGIBLE PLANT	P90	0	0	0	6
7						7
8	TOTAL CWP - MAJOR PROJECTS		0	0	0	8
9						9
10						10
11	CONST WORK-IN-PROGRESS - SHORT TERM					11
12	PRODUCTION PLANT	P10	144,982	54,975	90,008	12
13	TRANSMISSION PLANT	D2	574,600	225,039	349,561	13
14	DISTRIBUTION PLANT	P60	3,202,386	1,418,914	1,783,482	14
15	GENERAL PLANT	P90	1,304,249	516,762	787,467	15
16	INTANGIBLE PLANT	P90	0	0	0	16
17						17
18	TOTAL CWP - SHORT TERM		5,226,428	2,215,710	3,010,718	18
19						19
20						20
21	CONST WORK-IN-PROGRESS - LONG TERM					21
22	PRODUCTION PLANT	P10	13,197,861	0	13,197,861	22
23	TRANSMISSION PLANT	D2	3,742,692	0	3,742,692	23
24	DISTRIBUTION PLANT	P60	2,703,641	0	2,703,641	24
25	GENERAL PLANT	P90	1,167,240	0	1,167,240	25
26	INTANGIBLE PLANT	P90	0	0	0	26
27						27
28	TOTAL CWP - LONG TERM		20,811,434	0	20,811,434	28
29						29
30						30
31	TOTAL CONSTRUCTION WORK-IN-PROGRESS		26,037,862	2,215,710	23,822,152	31
32						32
33	MATERIALS & SUPPLIES					33
34	PRODUCTION	P10	3,772,973	1,430,641	2,342,332	34
35	TRANSMISSION	D2	3,598,449	1,408,823	2,189,626	35
36	DISTRIBUTION	P60	6,127,090	2,714,784	3,412,306	36
37						37
38	TOTAL MATERIALS AND SUPPLIES		13,498,511	5,554,248	7,944,264	38
39						39
40						40
41	FUEL STOCKS					41
42	COAL STOCKS	E1	5,708,035	2,123,537	3,584,498	42
43	FUEL OIL STOCKS	D1	1,930,934	763,547	1,167,387	43
44						44
45	TOTAL FUEL STOCKS		7,638,969	2,887,084	4,751,885	45
46						46
47	PREPAYMENTS					47
48		NEPIS	(35,518,043)	(14,003,394)	(21,514,649)	48
49	CUSTOMER ADVANCES	NEPIS	(126,099)	(50,899)	(78,200)	49
50						50
51	CASH WORKING CAPITAL	OX	10,112,418	4,811,395	5,301,022	51
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OTTER TAIL POWER COMPANY
COST OF SERVICE STUDY
ACTUAL YEAR 2007 - 10 CLASSES

LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	ACCUMULATED DEFERRED INCOME TAXES					1
2	ITEMS SD FLOWS THROUGH					2
3	FEDERAL		(4,448,066)	(1,967,400)	(2,481,666)	3
4	MINNESOTA		(671,579)	0	(671,579)	4
5	NORTH DAKOTA		(391,628)	(390,134)	(1,494)	5
6						6
7	SUBTOTAL		(5,512,272)	(2,357,534)	(3,154,738)	7
8	ALL OTHER					8
9	FEDERAL		(61,140,220)	(24,105,234)	(37,034,996)	9
10	MINNESOTA		(8,487,794)	0	(8,487,794)	10
11	NORTH DAKOTA		(4,391,625)	(4,374,868)	(16,757)	11
12						12
13	SUBTOTAL		(74,019,639)	(28,480,102)	(45,539,536)	13
14						14
15	TOTAL ACCUMULATED DEFERRED INCOME TAXES		(79,531,911)	(30,837,636)	(48,694,275)	15
16						16
17	UNAMORTIZED BALANCE - SPIRITWOOD PLANT					17
18			0	0	0	18
19						19
20						20
21	UNAMORTIZED RATE CASE EXPENSES		0	0	0	21
22						22
23						23
24						24
25						25
26						26
27	TOTAL AVERAGE RATE BASE		435,419,236	165,070,791	270,348,445	27
28						28
29						29
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OTTER TAIL POWER COMPANY
COST OF SERVICE STUDY
ACTUAL YEAR 2007 - 10 CLASSES

LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	OPERATING REVENUES					1
2	SALES OF ELECTRICITY		268,698,170	108,472,410	160,225,760	2
3	OTHER OPERATING REVENUE		33,215,346	12,622,188	20,594,158	3
4						4
5	TOTAL OPERATING REVENUE		301,914,516	121,094,598	180,819,918	5
6						6
7						7
8	OPERATING EXPENSES					8
9	PRODUCTION EXPENSES		160,332,203	62,106,875	98,225,327	9
10	TRANSMISSION EXPENSES		10,492,992	4,108,094	6,384,898	10
11	DISTRIBUTION EXPENSES		14,686,349	6,461,701	8,224,648	11
12	CUSTOMER ACCOUNTING EXPENSES		10,507,260	4,445,093	5,962,177	12
13	CUSTOMER SERVICE AND INFORMATION EXPENSES		9,241,699	1,153,127	4,088,572	13
14	SALES EXPENSES		1,121,951	628,984	492,966	14
15	ADMINISTRATIVE AND GENERAL EXPENSES		31,637,814	12,293,584	19,344,230	15
16	CHARITABLE CONTRIBUTIONS		111,967	0	111,967	16
17	DEPRECIATION EXPENSE		24,636,391	10,157,335	14,679,056	17
18	AMORTIZATION OF BIG STONE PLANT CAPITALIZED COSTS		0	0	0	18
19	SPIRITWOOD AMORTIZATION		0	0	0	19
20	GENERAL TAXES		9,411,607	3,710,634	5,700,973	20
21						21
22	TOTAL OPERATING EXPENSES		268,590,233	105,165,417	163,424,815	22
23						23
24				0		24
25	NET OPERATING INCOME BEFORE INCOME TAXES		33,334,283	15,928,181	17,406,103	25
26						26
27						27
28	INCOME TAX EXPENSE					28
29	INVESTMENT TAX CREDIT		(1,136,657)	(459,510)	(677,147)	29
30	DEFERRED INCOME TAXES		477,922	207,151	270,771	30
31	INCOME TAXES		8,005,239	4,298,276	3,706,962	31
32						32
33	TOTAL INCOME TAX EXPENSE		7,346,504	4,045,918	3,300,586	33
34						34
35						35
36						36
37	NET OPERATING INCOME		25,987,779	11,883,263	14,104,517	37
38						38
39						39
40	ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION		2,257,062	0	2,257,062	40
41						41
42	TOTAL AVAILABLE FOR RETURN		28,244,841	11,883,263	16,361,579	42
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OTTER TAIL POWER COMPANY
COST OF SERVICE STUDY
ACTUAL YEAR 2007 - 10 CLASSES

LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	OPERATING REVENUES					1
2						2
3	SALES OF ELECTRICITY		268,698,170	108,472,410	160,225,760	3
4						4
5						5
6	OTHER OPERATING REVENUES					6
7	SALES FOR RESALE					7
8	MUNICIPALITIES & OFF SYSTEM SALES		211,432	0	211,432	8
9	NON-ASSOCIATED UTILITIES, CO-OPS & OPA		0	0	0	9
10	BUY SELL TRANSACTIONS		0	0	0	10
11	ALL OTHER TRANSACTIONS		0	0	0	11
12	BASE DEMAND		0	0	0	12
13	PEAK DEMAND		0	0	0	13
14	BASE ENERGY		20,133,608	7,817,861	12,315,727	14
15	PEAK ENERGY		0	0	0	15
16						16
17	TOTAL ALL OTHER TRANSACTIONS		20,133,608	7,817,861	12,315,727	17
18						18
19	TOTAL SALES FOR RESALE		20,945,040	7,817,861	12,527,159	19
20						20
21						21
22	OTHER ELECTRIC REVENUES					22
23	LATE FEES		545,326	170,779	374,547	23
24	CONNECTION FEES		315,745	88,754	225,991	24
25	RENT FROM ELECTRIC PROPERTY - BIG STONE		644,002	253,905	390,097	25
26	RENT FROM ELECTRIC PROPERTY - COYOTE		(20,657)	(8,144)	(12,513)	26
27	RENT FROM ELECTRIC REVENUE		11,846	4,670	7,175	27
28	OTHER MISC ELECTRIC REVENUE		2,719,318	1,072,122	1,647,196	28
29	ITA DEFICIENCY PAYMENTS		3,851,858	1,438,787	2,212,071	29
30	NEPIS		0	0	0	30
31	MISCELLANEOUS SERVICES		34,025	13,415	20,610	31
32	WHEELING		433,023	0	433,023	32
33	LOAD CONTROL AND DISPATCH		4,458,926	1,758,377	2,701,549	33
34	RESIDENTIAL CONSERVATION SERVICES		76,895	9,642	67,252	34
35						35
36	TOTAL OTHER ELECTRIC REVENUES		12,871,306	4,804,307	8,066,999	36
37						37
38	TOTAL OTHER OPERATING REVENUES		33,216,346	12,622,188	20,594,158	38
39						39
40						40
41	TOTAL OPERATING REVENUES		301,914,516	121,094,598	180,819,918	41
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OTTER TAIL POWER COMPANY
COST OF SERVICE STUDY
ACTUAL YEAR 2007 - 10 CLASSES

LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	OPERATING EXPENSES					1
2	PRODUCTION EXPENSES					2
3	PROD EXPENSES EXCLUDING PURCHASED POWER					3
4	BASE DEMAND	E1	10,208,213	3,797,720	6,410,493	4
5	PEAK DEMAND	D1	5,057,494	1,990,879	3,057,615	5
6	BASE ENERGY	E2	62,473,643	24,258,519	38,215,125	6
7	PEAK ENERGY	D1	6,236,150	2,465,954	3,770,197	7
8						8
9	TOTAL EXCLUDING PURCHASED POWER		83,975,500	32,522,071	51,453,429	9
10						10
11	PURCHASED POWER					11
12	BUY SELL TRANSACTIONS		0	0	0	12
13	ALL OTHER TRANSACTIONS	D2				13
14	BASE DEMAND	E1	3,963,752	1,474,618	2,489,134	14
15	PEAK DEMAND	D1	0	0	0	15
16	BASE ENERGY	E2	72,392,950	28,110,186	44,282,764	16
17	PEAK ENERGY	D1	0	0	0	17
18						18
19	TOTAL ALL OTHER TRANSACTIONS		76,356,702	29,584,804	46,771,897	19
20						20
21	TOTAL PURCHASED POWER		76,356,702	29,584,804	46,771,897	21
22						22
23	TOTAL PRODUCTION EXPENSES		160,332,202	62,106,875	98,225,327	23
24						24
25	TRANSMISSION EXPENSES					25
26						26
27		D2	10,482,982	4,108,094	6,384,888	27
28						28
29						29
30	DISTRIBUTION EXPENSES					30
31	PRIMARY DEMAND	D3	4,157,949	1,826,513	2,331,437	31
32	SECONDARY DEMAND	D4	1,331,858	612,834	719,024	32
33	PRIMARY CUSTOMER	C2	2,841,193	1,252,967	1,588,226	33
34	SECONDARY CUSTOMER	C3	2,298,330	1,013,906	1,284,424	34
35	STREET LIGHTING	C4	1,508,249	634,223	874,026	35
36	AREA LIGHTING	C5	42,974	20,000	22,974	36
37	METERS	C6	2,505,796	1,101,257	1,404,540	37
38	LOAD MANAGEMENT	C9	0	0	0	38
39						39
40	TOTAL DISTRIBUTION	OXD	14,686,349	6,461,701	8,224,648	40
41						41
42	CUSTOMER ACCOUNTING EXPENSES					42
43	METER READING	C7	4,654,956	1,964,632	2,690,324	43
44	OTHER	C8	5,852,304	2,580,451	3,271,853	44
45						45
46	TOTAL CUSTOMER ACCOUNTS	OXC	10,507,260	4,545,083	5,962,177	46
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OTTER TAIL POWER COMPANY
COST OF SERVICE STUDY
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LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	CUSTOMER SERVICE & INFORMATION EXPENSE					1
2	CONSERVATION & PROMOTIONAL REBATES	C1	2,618,980	0	2,618,980	2
3	OTHER	C1	2,622,720	1,153,127	1,469,593	3
4						4
5	TOTAL CUSTOMER SERV & INFORMATION EXP	OXI	5,241,699	1,153,127	4,088,572	5
6						6
7	SALES EXPENSES					7
8	OFF-PEAK DEVELOPMENT					8
9	OTHER	C1	653,705	427,508	226,197	9
10		C1	458,245	201,476	256,769	10
11						11
12	TOTAL SALES EXPENSES		1,121,951	628,984	492,966	12
13						13
14	ADMINISTRATIVE & GENERAL EXPENSES					14
15	SALARIES, SUPPLIES, PENSIONS & BENEFITS					15
16	PRODUCTION	OXPD	8,158,534	3,085,403	5,073,131	16
17	TRANSMISSION	D2	3,122,884	1,222,639	1,900,255	17
18	DISTRIBUTION	OXD	5,549,842	2,441,820	3,108,022	18
19	CUSTOMER ACCOUNTS	OXD	3,967,339	1,716,136	2,251,203	19
20	CUSTOMER SERVICE & INFO	C1	1,365,297	600,278	765,019	20
21						21
22	TOTAL SALARIES, SUPPLIES, PENSIONS, AND BENEFITS		22,103,906	9,066,276	13,037,631	22
23						23
24	LOAD MANAGEMENT EXPENSES	C9	0	0	0	24
25						25
26	OUTSIDE SERVICES	NEPIS	1,595,302	628,966	966,336	26
27						27
28	PROPERTY INSURANCE	NEPIS	974,518	384,215	590,303	28
29						29
30	INJURIES & DAMAGES	NEPIS	1,646,487	649,150	997,347	30
31						31
32	REGULATORY COMMISSION EXPENSE	R10	1,752,128	96,703	1,655,425	32
33						33
34	GENERAL ADVERTISING	C1	1,379	606	772	34
35						35
36	MISCELLANEOUS, RENTS, MAINTENANCE	P90	3,704,085	1,467,668	2,236,417	36
37						37
38	TOTAL ADMINISTRATIVE & GENERAL EXP		31,837,814	12,293,584	19,544,230	38
39						39
40						40
41	CHARITABLE CONTRIBUTIONS	C1	111,967	0	111,967	41
42						42
43						43
44						44
45	TOTAL O & M EXPENSES		234,332,234	91,297,449	143,034,786	45
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NORTH DAKOTA

OTTER TAIL POWER COMPANY
COST OF SERVICE STUDY
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LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	DEPRECIATION EXPENSE					1
2	PRODUCTION					2
3	BASE DEMAND					3
4	PEAK DEMAND					4
5	BASE ENERGY					5
6						6
7	TOTAL PRODUCTION		9,262,078	3,546,055	5,716,022	7
8						8
9						9
10	TRANSMISSION		3,947,740	1,527,896	2,419,844	10
11						11
12						12
13	DISTRIBUTION		8,775,992	3,918,044	4,857,948	13
14						14
15						15
16	GENERAL		2,438,781	1,002,568	1,437,213	16
17						17
18						18
19	INTANGIBLE		410,801	162,771	248,029	19
20						20
21						21
22	TOTAL DEPRECIATION EXPENSE		24,536,381	10,157,335	14,679,055	22
23						23
24						24
25						25
26						26
27						27
28						28
29	BIG STONE EXPENSE OFFSETS		0	0	0	29
30						30
31						31
32	SPIRITWOOD AMORTIZATION		0	0	0	32
33						33
34						34
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OTTER TAIL POWER COMPANY
COST OF SERVICE STUDY
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LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	GENERAL TAXES	NEPIS	9,411,607	3,710,634	5,700,973	1
2	NET OPERATING INCOME BEFORE TAX (NOIBT)		33,334,283	15,928,181	17,405,103	2
3						3
4						4
5	INVESTMENT TAX CREDIT	EPIS	(1,136,657)	(459,510)	(677,147)	5
6	AMORTIZE PRIOR YEARS CREDIT	EPIS	0	0	0	6
7	DEBITS UTILIZED					7
8						8
9	TOTAL INVESTMENT TAX CREDIT		(1,136,657)	(459,510)	(677,147)	9
10						10
11	DEFERRED INCOME TAXES					11
12	ITEMS SOUTH DAKOTA FLOWS THROUGH					12
13	FEDERAL	NPINR	597,347	259,728	327,619	13
14	MINNESOTA	NPISM	66,062	0	66,062	14
15	NORTH DAKOTA	NPISN	53,223	53,020	203	15
16						16
17	SUB TOTAL		706,232	312,748	396,484	17
18						18
19	ALL OTHER					19
20	FEDERAL	NEPIS	(260,385)	(102,660)	(157,725)	20
21	MINNESOTA	NPISM	32,023		32,023	21
22	NORTH DAKOTA	NPISN	(2,948)	(2,937)	(11)	22
23						23
24	SUB TOTAL		(231,310)	(105,597)	(125,713)	24
25						25
26	TOTAL DEFERRED INCOME TAXES		477,922	207,151	270,771	26
27						27
28				0		28
29	CURRENT INCOME TAXES			0		29
30	FEDERAL INCOME TAXES		6,731,921	3,587,086	3,144,835	30
31	MINNESOTA INCOME TAXES		562,411	0	562,411	31
32	NORTH DAKOTA INCOME TAXES		710,907	711,191	(284)	32
33						33
34	TOTAL CURRENT INCOME TAXES		8,005,239	4,298,276	3,706,962	34
35						35
36	TOTAL INCOME TAXES		7,346,504	4,045,918	3,300,586	36
37						37
38						38
39	NET OPERATING INCOME		25,987,779	11,883,263	14,104,517	39
40						40
41	AFDC		2,257,062	0	2,257,062	41
42						42
43	TOTAL AVAILABLE FOR RETURN		28,244,841	11,883,263	16,361,579	43
44						44
45						45
46	RATE OF RETURN ON RATE BASE		6.49%	7.20%	6.05%	46
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OTTER TAIL POWER COMPANY
COST OF SERVICE STUDY
ACTUAL YEAR 2007 - 10 CLASSES

LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	DEVELOPMENT OF FEDERAL INCOME TAX EXPENSE					1
2	NET OPERATING INCOME BEFORE TAX (NOBT)		33,334,203	15,920,181	17,405,103	2
3	LESS: INTEREST COST		11,554,307	4,480,926	7,064,471	3
4						4
5	NET INCOME BEFORE TAX		21,779,897	11,439,255	10,340,632	5
6						6
7	FEDERAL SCHEDULE M ADJUSTMENTS:					7
8	ADDITIONAL TAX DEPRECIATION		2,701,204	1,065,016	1,636,278	8
9	COST TO REMOVE		3,949,203	1,567,018	2,382,185	9
10	DIRECTLY ASSIGNED SCHEDULE M ITEMS		(33,287)	(59,223)	(34,054)	10
11	ACCURED VACATION PAY		87,932	34,668	53,264	11
12	CHARGES - OPERATING RESERVES		4,671,607	1,941,913	2,829,694	12
13	PROVISIONS - OPERATING RESERVES		(8,596,414)	(3,350,023)	(5,246,391)	13
14	UNBILLED REVENUES		0	0	0	14
15	PREFERRED DIVIDENDS PAID CREDIT		160,775	63,367	97,388	15
16	OTHER SCHEDULE M ITEMS		(1,606,800)	(633,499)	(973,301)	16
17						17
18	SUBTOTAL FEDERAL SCHEDULE M ADJUSTMENTS		1,272,510	479,248	793,262	18
19						19
20	FEDERAL ADJUSTED INCOME BEFORE INCOME TAXES		20,507,377	10,960,007	9,547,370	20
21						21
22	LESS:					22
23	MINNESOTA STATE INCOME TAXES		562,411	0	562,411	23
24	NORTH DAKOTA STATE INCOME TAXES		710,907	711,191	(284)	24
25						25
26	FEDERAL TAXABLE INCOME		19,234,059	10,248,817	8,985,242	26
27	FEDERAL TAX RATE		35.00%	35.00%	35.00%	27
28	FEDERAL INCOME TAX BEFORE CREDITS		6,731,921	3,587,086	3,144,835	28
29	INVESTMENT TAX CREDIT - DEBITS UTILIZED		0	0	0	29
30						30
31	FEDERAL INCOME TAXES		6,731,921	3,587,086	3,144,835	31
32						32
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OTTER TAIL POWER COMPANY
COST OF SERVICE STUDY
ACTUAL YEAR 2007 - 10 CLASSES

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LINE NO	ITEM	ALLOC	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	DEVELOPMENT OF MINNESOTA STATE INCOME TAX EXPENSE					1
2	FEDERAL ADJUSTED INCOME BEFORE INCOME TAXES		7,651,214	0	7,651,214	2
3						3
4	MINNESOTA ADJUSTMENTS TO FEDERAL SCHEDULE M:					4
5	PAY/SOP ADJUSTMENT	NEPIS	0	0	0	5
6	CHANGE IN EXCESS TAX DEPRECIATION - MN	NEPIS	(2,460,048)	0	(2,460,048)	6
7	CHANGE IN ACRS - ORDINARY LOSS	NEPIS	0	0	0	7
8	PREFERRED DIVIDENDS PAID CREDIT	NEPIS	79,956	0	79,956	8
9	MISCELLANEOUS ADJUSTMENTS TO FED SCHEDULE M	NEPIS	467,770	0	467,770	9
10						10
11	TOTAL MINNESOTA ADJUSTMENTS TO FED SCHEDULE M		(1,912,322)	0	(1,912,322)	11
12	MINNESOTA TAXABLE INCOME		5,738,893	0	5,738,893	12
13	MINNESOTA TAX RATE		9.80%	0.00%	9.80%	13
14	MINNESOTA INCOME TAX		562,411	0	562,411	14
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16						16
17						17
18						18
19						19
20						20
21						21
22						22
23						23
24						24
25	DEVELOPMENT OF NORTH DAKOTA STATE INCOME TAX EXPENSE		10,942,542	10,960,007	(17,460)	25
26	FEDERAL ADJUSTED INCOME BEFORE INCOME TAXES					26
27						27
28	NORTH DAKOTA ADJUSTMENTS TO FEDERAL SCHEDULE M:					28
29	CHANGE IN EXCESS TAX DEPRECIATION - ND	NEPIS	(7,373)	(7,297)	(76)	29
30	CHANGE IN ACRS - ORDINARY LOSS - ND	NEPIS	0	0	0	30
31	CHANGE IN INCOME FROM ADR PROPERTY - ND	NEPIS	0	0	0	31
32	MISCELLANEOUS ADJUSTMENTS TO FED SCHEDULE M	NEPIS	(3,585)	(3,548)	(37)	32
33						33
34	TOTAL NORTH DAKOTA ADJUSTMENTS TO FED SCHEDULE M		(10,959)	(10,845)	(113)	34
35	SUBTOTAL		10,931,583	10,949,162	(17,579)	35
36	DEDUCTION OF FEDERAL INCOME TAXES		(5,443)	0	(5,443)	36
37						37
38	NORTH DAKOTA TAXABLE INCOME		10,937,026	10,949,162	(12,136)	38
39	NORTH DAKOTA TAX RATE		6.50%	6.50%	6.50%	39
40						40
41						41
42	NORTH DAKOTA INCOME TAX		710,907	711,191	(284)	42
43						43
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NORTH DAKOTA

OTTER TAIL POWER COMPANY COST OF SERVICE STUDY ACTUAL YEAR 2007 - 10 CLASSES	RUN =		ACTUAL	PAGE 15 - 1
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LINE NO	ITEM	ALLOCATION FACTOR	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	MWH CONSUMPTION AT GENERATORS - PARTIAL PERCENTAGE	E1	3,918,074	1,457,625	2,460,449	1
2			100.000000%	37.202590%	62.797410%	2
3						3
4			4,430,839	1,720,495	2,710,344	4
5	MWH CONSUMPTION AT GENERATORS - TOTAL PERCENTAGE	E2	100.000000%	38.830005%	61.169995%	5
6						6
7			598,234	236,559	361,675	7
8			100.000000%	39.542883%	60.457117%	8
9	GENERATION DEMAND FACTOR PERCENTAGE	D1				9
10			604,225	236,559	367,666	10
11			100.000000%	39.150634%	60.849366%	11
12						12
13	DISTRIBUTION - PRIMARY DEMAND FACTOR PERCENTAGE	D3	757,342	332,687	424,655	13
14			100.000000%	43.928211%	56.071789%	14
15						15
16			998,227	459,319	538,908	16
17	DISTRIBUTION - SECONDARY DEMAND FACTOR PERCENTAGE	D4	100.000000%	46.013482%	53.986518%	17
18						18
19						19
20			128,675	57,014	72,661	20
21	CUSTOMER OR METER FACTORS TOTAL RETAIL CUSTOMERS PERCENTAGE	C1	100.000000%	43.966840%	56.033160%	21
22						22
23			135,857	59,913	75,944	23
24			100.000000%	44.100046%	55.899954%	24
25	RETAIL SERVICE LOCATIONS PERCENTAGE	C2				25
26			135,784	59,901	75,883	26
27			100.000000%	44.114918%	55.885082%	27
28						28
29	SECONDARY SERVICE LOCATIONS PERCENTAGE	C3	4,185,546	1,760,035	2,425,511	29
30			100.000000%	42.050308%	57.949692%	30
31						31
32			3,688,552	1,716,671	1,971,881	32
33	AREA LIGHTING FACTOR PERCENTAGE	C5	100.000000%	46.540512%	53.459488%	33
34						34
35			29,240,646	12,850,789	16,389,857	35
36			100.000000%	43.948376%	56.051624%	36
37	METER FACTOR PERCENTAGE	C6				37
38			173,474	73,215	100,259	38
39			100.000000%	42.205172%	57.794828%	39
40						40
41	METER READING FACTOR PERCENTAGE	C7	135,879	59,913	75,966	41
42			100.000000%	44.092906%	55.907094%	42
43						43
44			40,923	18,040	22,883	44
45	LOAD MANAGEMENT FACTOR PERCENTAGE	C9	100.000000%	44.082790%	55.917210%	45
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OTTER TAIL POWER COMPANY
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LINE NO	ITEM	ALLOCATION FACTOR	TOTAL COMPANY	NORTH DAKOTA	OTHER	LINE NO
0						1
1	GROSS PLANT IN SERVICE	P10	366,910,631	139,125,650	227,784,981	2
2	PRODUCTION PLANT		100,000,000%	37,918,130%	62,081,870%	3
3	PERCENTAGE					4
4						5
5	DISTRIBUTION PLANT	P80	315,099,950	139,614,140	175,485,810	6
6	PERCENTAGE		100,000,000%	44,307,890%	55,692,110%	7
7						8
8	GENERAL PLANT	P80	70,354,613	27,576,579	42,778,034	9
9	PERCENTAGE		100,000,000%	39,622,959%	60,377,041%	10
10						11
11	ELECTRIC PLANT IN SERVICE	EPIS	946,761,213	382,741,667	564,019,546	12
12	PERCENTAGE		100,000,000%	40,426,420%	59,573,500%	13
13						14
14	NET ELECTRIC PLANT IN SERVICE	NEPIS	493,280,843	194,481,610	298,799,233	15
15	PERCENTAGE		100,000,000%	39,426,143%	60,573,857%	16
16						17
17	OPERATION AND MAINTENANCE EXPENSE	OXPD	19,229,459	7,272,217	11,957,242	18
18	PRODUCTION EXPENSE (EXCL ENERGY)		100,000,000%	37,818,105%	62,181,895%	19
19	PERCENTAGE					20
20						21
21	DISTRIBUTION EXPENSE	OXD	14,686,349	6,461,701	8,224,648	22
22	PERCENTAGE		100,000,000%	43,998,008%	56,001,992%	23
23						24
24	CUSTOMER ACCOUNTS EXPENSE	OXC	10,507,260	4,545,083	5,962,177	25
25	PERCENTAGE		100,000,000%	43,256,697%	56,743,403%	26
26						27
27	CUSTOMER SERVICE & INFORMATION EXPENSE	OXI	5,241,699	1,153,127	4,088,572	28
28	PERCENTAGE		100,000,000%	21,999,105%	78,000,895%	29
29						30
30	OTHER DEFERRED INCOME TAX FACTOR					31
31	MINNESOTA	NPISM	244,543,074	0	244,543,074	32
32	PERCENTAGE		100,000,000%	0,000,000%	100,000,000%	33
33						34
34	NORTH DAKOTA	NPISN	195,226,513	194,481,610	744,903	35
35	PERCENTAGE		100,000,000%	99,618,442%	0,381,559%	36
36						37
37	EXCLUDING SOUTH DAKOTA	NPMNR	439,799,457	194,481,610	245,317,847	38
38	PERCENTAGE		100,000,000%	44,220,521%	55,779,479%	39
39						40
40	LONG-TERM CWP RATIO (W/AFDC)	CWPLT	20,811,434	0	20,811,434	41
41	PERCENTAGE		100,000,000%	0,000,000%	100,000,000%	42
42						43
43	REVENUE	R10	288,698,170	108,472,410	160,225,760	44
44	PERCENTAGE		100,000,000%	40,369,612%	59,630,388%	45
45						46
46	LABOR AND RELATED EXPENSE	LRE	91,995,573	35,833,806	56,161,767	47
47	PERCENTAGE		100,000,000%	38,951,663%	61,048,337%	48
48						49
49	TOTAL O & M EXPENSE	OX				50
50	PERCENTAGE					51
51						52
52						53
53						54
54						55
55						56
56						57
57						58
58						59
59						60

LINE NO	ITEM	AMOUNT	AMOUNT AS A PERCENT OF TOTAL	COST OF CAPITAL	RATE OF RETURN	LINE NO
1						1
2						2
3						3
4	CAPITAL STRUCTURE - RATE OF RETURN					4
5						5
6	LONG-TERM DEBT	185,725,713	43.106%	6.30%	2.72%	6
7	PREFERRED STOCK	15,500,000	3.597%	4.75%	0.17%	7
8	COMMON EQUITY	229,833,133	53.297%	11.25%	6.00%	8
9						9
10						10
11	TOTAL	\$430,858,846	100.00%		8.89%	11
12						12
13						13
14						14
15						15
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60						60

OTTER TAIL POWER COMPANY
COST OF SERVICE STUDY
ACTUAL YEAR 2007 - 10 CLASSES

OTTER TAIL POWER COMPANY
COST OF SERVICE STUDY
ACTUAL YEAR 2007 - 10 CLASSES

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LINE NO	ITEM	ALLOCATION	TOTAL COMPANY	NORTH DAKOTA	ALL OTHER	LINE NO
1	CASH WORKING CAPITAL CALCULATION - REVENUE LEAD DAYS					1
2	REVENUES					2
3	COMPUTER MAINTAINED BILLINGS		210,328,769	83,927,881	126,400,888	3
4	MANUALLY MAINTAINED BILLINGS		18,869,929	7,529,703	11,340,226	4
5	COST OF ENERGY REVENUES	R10	40,397,002	17,276,360	23,121,642	5
6	SALES FOR RESALE		20,308,582	7,817,881	12,490,701	6
7	RENT FROM ELECTRIC PROPERTY		644,002	253,905	390,097	7
8	MISCELLANEOUS		2,719,318	1,072,122	1,647,196	8
9	ITA DEFICIENCY PAYMENTS		3,651,888	1,439,787	2,212,071	9
10	WHEELING		433,023	0	433,023	10
11	LOAD CONTROL AND DISPATCH		4,459,926	1,758,377	2,701,549	11
12	RENT FROM ELECTRIC PROPERTY - BIG STONE		(20,657)	(8,144)	(12,513)	12
13	RENT FROM ELECTRIC PROPERTY - COYOTE		11,846	4,670	7,175	13
14	PROFIT ON MATERIALS AND SUPPLIES		0	0	0	14
15	RUBBER GOODS TESTING		34,025	13,415	20,610	15
16	RESIDENTIAL CONSERVATION SERVICES		76,895	9,642	67,252	16
17	TOTAL REVENUES		301,914,516	121,094,598	180,819,918	17
18						18
19	REVENUE LEAD DAYS FROM SERVICE TO COLLECTION					19
20	COMPUTER MAINTAINED BILLINGS		N/A	38.1	N/A	20
21	MANUALLY MAINTAINED BILLINGS		N/A	43.1	N/A	21
22	COST OF ENERGY REVENUES		N/A	177.8	N/A	22
23	SALES FOR RESALE		N/A	25.4	N/A	23
24	RENT FROM ELECTRIC PROPERTY		N/A	46.4	N/A	24
25	MISCELLANEOUS		N/A	35.0	N/A	25
26	ITA DEFICIENCY PAYMENTS		N/A	53.2	N/A	26
27	WHEELING		N/A	37.8	N/A	27
28	LOAD CONTROL AND DISPATCH		N/A	33.6	N/A	28
29	RENT FROM ELECTRIC PROPERTY - BIG STONE		N/A	50.2	N/A	29
30	RENT FROM ELECTRIC PROPERTY - COYOTE		N/A	50.2	N/A	30
31	PROFIT ON MATERIALS AND SUPPLIES		N/A	50.2	N/A	31
32	RUBBER GOODS TESTING		N/A	50.2	N/A	32
33	RESIDENTIAL CONSERVATION SERVICES		N/A	50.2	N/A	33
34						34
35	REVENUE DOLLAR DAYS (REVENUES X REVENUE LEAD DAYS)					35
36	COMPUTER MAINTAINED BILLINGS		8,013,526,084	3,197,652,252	4,815,873,832	36
37	MANUALLY MAINTAINED BILLINGS		813,293,929	324,530,193	488,763,737	37
38	COST OF ENERGY REVENUES		4,522,367,678	2,207,790,384	2,314,576,694	38
39	SALES FOR RESALE		515,837,988	198,574,177	317,263,812	39
40	RENT FROM ELECTRIC PROPERTY		(65,641,744)	(21,937,394)	(33,704,351)	40
41	MISCELLANEOUS		95,176,121	37,524,273	57,651,847	41
42	ITA DEFICIENCY PAYMENTS		194,278,846	76,596,655	117,682,190	42
43	WHEELING		16,368,267	0	16,368,267	43
44	LOAD CONTROL AND DISPATCH		149,853,514	59,061,460	90,772,053	44
45	RENT FROM ELECTRIC PROPERTY - BIG STONE		(975,657)	(408,836)	(567,022)	45
46	RENT FROM ELECTRIC PROPERTY - COYOTE		559,610	234,449	325,161	46
47	PROFIT ON MATERIALS AND SUPPLIES		0	0	0	47
48	RUBBER GOODS TESTING		1,607,399	673,420	933,979	48
49	RESIDENTIAL CONSERVATION SERVICES		3,493,444	484,038	3,009,406	49
50	TOTAL DOLLAR DAYS		14,269,745,278	6,080,795,672	8,188,949,607	50
51						51
52	AVG REVENUE LEAD DAYS (TOTAL REV DOLLAR DAYS / TOTAL REV)		47.3	50.2	45.3	52
53						53
54						54
55						55
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OTTER TAIL POWER COMPANY COST OF SERVICE STUDY ACTUAL YEAR 2007 - 10 CLASSES										RUN =		ACTUAL 10/24/08 09:02 AM		PAGE 19 - 1	
LINE NO	ITEM	OPERATING EXPENSE	EXPENSE PER DAY AT 365 DAYS PER YEAR	EXPENSE LAG DAYS	EXCESS REVENUE LEAD DAYS OF OVER EXPENSE LAG DAYS	NET REVENUE LAG DOLLARS	LINE NO								
1	CASH WORKING CAPITAL CALCULATION BY THE APPLICATION OF														
2	LEAD-LAG FACTORS-MINNESOTA JURISDICTION														
3	FUEL - COAL	27,305,063	74,808	16.0	28.7	2,147,001	1								
4	FUEL - OIL	3,891,775	10,662	8.9	35.8	381,714	2								
5							3								
6	PURCHASED POWER	39,303,106	107,680	32.8	11.9	1,281,389	4								
7							5								
8	LABOR AND ASSOCIATED PAYROLL EXPENSE	30,882,779	84,610	13.9	30.8	2,605,999	6								
9							7								
10	ALL OTHER O&M EXPENSE	18,913,245	51,817	19.4	25.3	1,310,973	8								
11							9								
12	PROPERTY TAXES (EXCL COAL CONVERSION TAXES)	4,270,166	11,699	318.6	-273.9	(3,203,922)	10								
13							11								
14	COAL CONVERSION TAXES	371,813	1,019	318.6	-273.9	(278,973)	12								
15							13								
16	FEDERAL INCOME TAXES	2,489,777	6,821	43.9	0.8	5,457	14								
17							15								
18	STATE INCOME TAXES	566,824	1,553	20.7	24.0	37,271	16								
19							17								
20	INCREMENTAL FEDERAL INCOME TAXES	0	0	43.9	0.8	0	18								
21							19								
22	INCREMENTAL STATE INCOME TAXES	0	0	20.7	24.0	0	20								
23							21								
24	BANK BALANCES						22								
25							23								
26	SPECIAL DEPOSITS						24								
27							25								
28	WORKING FUNDS						26								
29							27								
30	TAX COLLECTIONS AVAILABLE - FICA WITHHOLDING	(2,055,239)	(5,631)	0.0		0	28								
31							29								
32	TAX COLLECTIONS AVAILABLE - FEDERAL WITHHOLDING	(3,505,486)	(9,604)	0.0		0	30								
33							31								
34	TAX COLLECTIONS AVAILABLE - STATE WITHHOLDING- MN	(1,835,219)	(4,480)	1.9		(8,512)	32								
35							33								
36	TAX COLLECTIONS AVAILABLE - STATE WITHHOLDING- ND	0	0	61.1		0	34								
37							35								
38	TAX COLLECTIONS AVAILABLE - STATE SALES TAX	(5,813,859)	(15,929)	15.5		(246,890)	36								
39							37								
40	TAX COLLECTIONS AVAILABLE - FRANCHISE TAXES	(722,428)	(1,979)	35.2		(69,670)	38								
41							39								
42							40								
43	TOTAL CASH WORKING CAPITAL REQUIREMENT - MINNESOTA					4,366,850	41								
44							42								
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OTTER TAIL POWER COMPANY COST OF SERVICE STUDY ACTUAL YEAR 2007 - 10 CLASSES				RUN = ACTUAL 10/24/08 09:02 AM		PAGE 20 - 1	
LINE NO	ITEM	OPERATING EXPENSE	EXPENSE PER DAY AT 365 DAYS PER YEAR	EXPENSE LAG DAYS	EXCESS REVENUE LEAD DAYS OF OVER EXPENSE LAG DAYS	NET REVENUE LAG DOLLARS	LINE NO
1	CASH WORKING CAPITAL CALCULATION BY THE APPLICATION OF						1
2	LEAD-LAG FACTORS-NORTH DAKOTA JURISDICTION						2
3	FUEL - COAL	20,630,427	56,522	16.0	34.2	1,933,043	3
4							4
5	FUEL - OIL	2,734,977	7,493	8.9	41.3	309,465	5
6		29,584,804	81,054	32.8	17.4	1,410,344	6
7	PURCHASED POWER	23,406,198	64,127	13.9	36.3	2,327,795	7
8							8
9	LABOR AND ASSOCIATED PAYROLL EXPENSE	14,941,042	40,934	19.4	30.8	1,260,778	9
10							10
11	ALL OTHER O&M EXPENSE	3,413,419	9,352	318.6	-268.4	(2,509,666)	11
12	PROPERTY TAXES (EXCL COAL CONVERSION TAXES)	297,214	814	318.6	-268.4	(218,522)	12
13							13
14	COAL CONVERSION TAXES	3,587,086	9,828	43.9	6.3	61,914	14
15	FEDERAL INCOME TAXES	711,191	1,948	73.0	-22.8	(44,425)	15
16	STATE INCOME TAXES	0	0	43.9	6.3	0	16
17	INCREMENTAL FEDERAL INCOME TAXES	0	0	73.0	(22.8)	0	17
18	INCREMENTAL STATE INCOME TAXES						18
19							19
20	BANK BALANCES					3,706	20
21	SPECIAL DEPOSITS					311,106	21
22							22
23	WORKING FUNDS					8,941	23
24						0	24
25	TAX COLLECTIONS AVAIL - FICA WITHHOLDING	(1,557,673)	(4,268)	0.0		0	25
26							26
27	TAX COLLECTIONS AVAIL - FEDERAL WITHHOLDING	(2,656,824)	(7,279)	0.0		0	27
28							28
29	TAX COLLECTIONS AVAIL - STATE WITHHOLDING- MN	0	0	1.9		0	29
30							30
31	TAX COLLECTIONS AVAIL - STATE WITHHOLDING- ND	(256,507)	(703)	61.1		(42,939)	31
32							32
33	TAX COLLECTIONS AVAILABLE - STATE SALES TAX	(2,020)	(6)	26.1		(144)	33
34							34
35	TAX COLLECTIONS AVAILABLE - FRANCHISE TAXES	0	0	0		0	35
36							36
37	TOTAL CASH WORKING CAPITAL REQUIREMENT - NORTH DAKOTA					4,811,395	37
38							38
39							39
40							40
41							41
42							42
43							43
44							44
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OTTER TAIL POWER COMPANY COST OF SERVICE STUDY ACTUAL YEAR 2007 - 10 CLASSES			RUN = ACTUAL 10/24/08 09:02 AM			PAGE 21 -1	
LINE NO	ITEM	OPERATING EXPENSE	EXPENSE PER DAY AT 365 DAYS PER YEAR	EXPENSE LAG DAYS	EXCESS REVENUE LEAD DAYS OF OVER EXPENSE LAG DAYS	NET REVENUE LAG DOLLARS	LINE NO
1	CASH WORKING CAPITAL CALCULATION BY THE APPLICATION OF LEAD-LAG FACTORS- SOUTH DAKOTA JURISDICTION						1
2	FUEL - COAL	5,148,528	14,108	16.0	32.4	457,109	2
3							3
4	FUEL - OIL	717,769	1,966	8.9	39.5	77,676	4
5							5
6	PURCHASED POWER	7,403,538	20,284	32.8	15.6	316,425	6
7							7
8	LABOR AND ASSOCIATED PAYROLL EXPENSE	5,489,661	15,068	13.9	34.5	519,831	8
9							9
10	ALL OTHER O&M EXPENSE	3,383,651	9,270	19.4	29.0	268,838	10
11	PROPERTY TAXES (EXCL COAL CONVERSION TAXES)	938,672	2,572	318.6	-270.2	(694,774)	11
12							12
13	COAL CONVERSION TAXES	81,732	224	318.6	-270.2	(60,496)	13
14							14
15	FEDERAL INCOME TAXES	670,013	1,836	43.9	4.5	8,260	15
16							16
17	STATE INCOME TAXES	0	0	0.0	48.4	0	17
18							18
19	INCREMENTAL FEDERAL INCOME TAXES	0	0	43.9	4.5	0	19
20							20
21	INCREMENTAL STATE INCOME TAXES	0	0	0.0	48.4	0	21
22							22
23	BANK BALANCES						23
24							24
25	SPECIAL DEPOSITS					1,019	25
26							26
27	WORKING FUNDS					85,552	27
28							28
29	TAX COLLECTIONS AVAIL - FICA WITHHOLDING					2,459	29
30							30
31	TAX COLLECTIONS AVAIL - FEDERAL WITHHOLDING	(366,000)	(1,003)	0.0	0	0	31
32							32
33	TAX COLLECTIONS AVAIL - STATE WITHHOLDING	(624,283)	(1,710)	0.0	0	0	33
34							34
35	TAX COLLECTIONS AVAIL - STATE WITHHOLDING- MN	0	0	1.9	0	0	35
36							36
37	TAX COLLECTIONS AVAIL - STATE WITHHOLDING- ND	0	0	61.1	0	0	37
38							38
39	TAX COLLECTIONS AVAILABLE - STATE SALES TAX	(1,212,766)	(3,323)	16.3	(54,189)	(54,189)	39
40							40
41	TAX COLLECTIONS AVAILABLE - FRANCHISE TAXES	0	0	0.0	0	0	41
42							42
43	TOTAL CASH WORKING CAPITAL REQUIREMENT - SOUTH DAKOTA					327,742	43
44							44
45							45
46							46
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OTTER TAIL POWER COMPANY COST OF SERVICE STUDY ACTUAL YEAR 2007 - 10 CLASSES									
LINE NO		ITEM	RUN = ACTUAL 10/24/08 09:02 AM				PAGE 22 -1		
			OPERATING EXPENSE	EXPENSE PER DAY AT 365 DAYS PER YEAR	EXPENSE LAG DAYS	EXCESS REVENUE LEAD DAYS OF OVER EXPENSE LAG DAYS	NET REVENUE LAG DOLLARS	LINE NO	
CASH WORKING CAPITAL CALCULATION BY THE APPLICATION OF LEAD-LAG FACTORS-FERC JURISDICTION									
1	E2	FUEL - COAL	45,098	124	16.0	21.9	2,706	1	
2								2	
3	E1	FUEL - OIL	7,057	19	8.9	29.0	561	3	
4								4	
5								5	
6								6	
7		PURCHASED POWER	65,254	179	32.8	5.1	912	7	
8								8	
9	LRE	LABOR AND ASSOCIATED PAYROLL EXPENSE	301,731	827	13.9	24.0	19,840	9	
10								10	
11		ALL OTHER O&M EXPENSE	165,531	454	19.4	18.5	8,390	11	
12								12	
13		PROPERTY TAXES (EXCL COAL CONVERSION TAXES)	35,489	97	318.6	-280.7	(27,296)	13	
14								14	
15		COAL CONVERSION TAXES	3,091	8	318.6	-280.7	(2,377)	15	
16								16	
17		FEDERAL INCOME TAXES	(14,778)	(40)	43.9	-6.0	243	17	
18								18	
19		STATE INCOME TAXES	(5,201)	(14)	43.9	-6.0	85	19	
20								20	
21		INCREMENTAL FEDERAL INCOME TAXES	0	0	43.9	-6.0	0	21	
22								22	
23		INCREMENTAL STATE INCOME TAXES	0	0	43.9	-6.0	0	23	
24								24	
25	NEPIS	BANK BALANCES					39	25	
26								26	
27	NEPIS	SPECIAL DEPOSITS					3,235	27	
28								28	
29	NEPIS	WORKING FUNDS					93	29	
30								30	
31	LRE	TAX COLLECTIONS AVAIL - FICA WITHHOLDING	(20,080)	(55)	0.0	0	0	31	
32								32	
33	LRE	TAX COLLECTIONS AVAIL - FEDERAL WITHHOLDING	(34,249)	(94)	0.0	0	0	33	
34								34	
35	R10	TAX COLLECTIONS AVAIL - STATE WITHHOLDING- MN	0	0	1.9	0	0	35	
36								36	
37	R10	TAX COLLECTIONS AVAIL - STATE WITHHOLDING- ND	0	0	61.1	0	0	37	
38								38	
39	R10	TAX COLLECTIONS AVAILABLE - STATE SALES TAX	0	0	0.0	0	0	39	
40								40	
41	R10	TAX COLLECTIONS AVAILABLE - FRANCHISE TAXES	0	0	0.0	0	0	41	
42								42	
43								43	
44		TOTAL CASH WORKING CAPITAL REQUIREMENT - FERC					6,431	44	
45								45	
46								46	
47								47	
48								48	
49								49	
50								50	
51								51	
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OTTER TAIL POWER COMPANY COST OF SERVICE STUDY ACTUAL YEAR 2007 - 10 CLASSES										RUN = ACTUAL 10/24/08 09:02 AM		PAGE 23 -1	
LINE NO	ITEM	OPERATING EXPENSE	EXPENSE PER DAY AT 365 DAYS PER YEAR	EXPENSE LAG DAYS	EXCESS REVENUE LEAD DAYS OF OVER EXPENSE LAG DAYS	NET REVENUE LAG DOLLARS	LINE NO						
1	CASH WORKING CAPITAL CALCULATION BY THE APPLICATION OF						1						
2	LEAD-LAG FACTORS - TOTAL CO.						2						
3	FUEL - COAL	E2				4,539,859	3						
4	FUEL - OIL	E1				769,416	4						
5							5						
6	PURCHASED POWER					3,009,070	6						
7							7						
8	LABOR AND ASSOCIATED PAYROLL EXPENSE	LRE				5,473,464	8						
9							9						
10	ALL OTHER O&M EXPENSE					2,848,979	10						
11							11						
12	PROPERTY TAXES (EXCL COAL CONVERSION TAXES)					(6,435,659)	12						
13							13						
14	COAL CONVERSION TAXES					(560,389)	14						
15							15						
16	FEDERAL INCOME TAXES					75,874	16						
17							17						
18	STATE INCOME TAXES					(7,069)	18						
19							19						
20	INCREMENTAL FEDERAL INCOME TAXES					0	20						
21							21						
22	INCREMENTAL STATE INCOME TAXES					0	22						
23							23						
24	BANK BALANCES					9,400	24						
25		NEPS					25						
26	SPECIAL DEPOSITS	NEPS				789,085	26						
27							27						
28	WORKING FUNDS	NEPS				22,679	28						
29							29						
30	TAX COLLECTIONS AVAIL - FICA WITHHOLDING	LRE				0	30						
31							31						
32	TAX COLLECTIONS AVAIL - FEDERAL WITHHOLDING	LRE				0	32						
33							33						
34	TAX COLLECTIONS AVAIL - STATE WITHHOLDING- MN	R10	ASSIGN TO JURIS			(8,512)	34						
35							35						
36	TAX COLLECTIONS AVAIL - STATE WITHHOLDING- ND	R10	ASSIGN TO JURIS			(42,939)	36						
37							37						
38	TAX COLLECTIONS AVAILABLE - STATE SALES TAX	R10				(301,193)	38						
39							39						
40	TAX COLLECTIONS AVAILABLE - FRANCHISE TAXES	R10				(89,670)	40						
41							41						
42							42						
43	TOTAL CASH WORKING CAPITAL REQUIREMENT - TOTAL COMPANY					10,112,418	43						
44							44						
45							45						
46							46						
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2007 Actual Year work papers

Functionalization

Line #		DESCRIPTION	ACCOUNTS		OPERATING STATEMENT AMOUNTS	2007	FUNCTIONALIZATION	Page 2 of 6
1	2		3	4	5			
STEAM POWER GENERATION:								
1	2	SUPERVISION AND ENGINEERING	401 - 500	(2)	1,394,608			1
2	3	FUEL	401 - 501		55,008,518			2
3	4	STEAM EXPENSE	401 - 502		3,191,009			3
4	5	ELECTRICAL EXPENSE	401 - 505		2,260,200			4
5	6	MISCELLANEOUS EXPENSE	401 - 506		4,140,261			5
6	7	RENT	401 - 507		3,216	65,997,811.67		6
7	8							7
STEAM POWER MAINTENANCE:								
9	10	SUPERVISION AND ENGINEERING	402 - 510		695,172			8
10	11	STRUCTURES	402 - 511		605,164			9
11	12	BOILER	402 - 512		5,918,965			10
12	13	ELECTRIC	402 - 513		887,113			11
13	14	MISCELLANEOUS	402 - 514		800,370	8,706,782.69		12
14	15							13
HYDRO:								
15	16	SUPERVISION AND ENGINEERING	401 - 535		65,688			14
16	17	ELECTRIC EXPENSE	401 - 538		59,043			15
17	18	MISCELLANEOUS EXPENSE	401 - 539		3,558			16
18	19	SUPERVISION & ENGINEERING	402 - 541		280	128,288.84		17
19	20	STRUCTURES	402 - 542		4,846			18
20	21	RESERVOIRS - DAMS	402 - 543		417,502			19
21	22	ELECTRIC	402 - 544		39,688			20
22	23	MISCELLANEOUS EXPENSE	402 - 545		18,991			21
23	24							22
24	25							23
IC:								
25	26	SUPERVISION AND ENGINEERING	401 - 546		37,444			24
26	27	FUEL	401 - 547		6,236,150			25
27	28	GENERATION EXPENSE	401 - 548		622,259			26
28	29	MISCELLANEOUS EXPENSE	401 - 549		68,914			27
29	30	RENTS	401 - 550		3,647	6,968,413.79		28
30	31	SUPERVISION AND ENGINEERING	402 - 551		48,987			29
31	32	STRUCTURES	402 - 552		3,337	1,256,128.75		30
32	33	GENERATING AND ELECTRIC	402 - 553		1,191,492			31
33	34	MISCELLANEOUS EXPENSE	402 - 554		12,313	73,094,514.30		32
34	35					10,444,218.96		33
35	36	OTHER POWER SUPPLY EXPENSES:						34
36	37	SYSTEM CONTROL AND DISPATCH	401 - 556		259,924			35
37	38	OTHER EXPENSES	401 - 557		1,847,801	2,107,724.20		36
38	39							37
TRANSMISSION EXPENSES:								
39	40	SUPERVISION AND ENGINEERING	401 - 560		511,139			38
40	41	LOAD DISPATCHING	401 - 561		2,791,737			39
41	42	STATION EXPENSE	401 - 562		160,433			40
42	43	OVERHEAD LINES	401 - 563		540,237			41
43	44	TRANSMISSION OF ELECTRICITY BY OTHERS	401 - 565		10,283			42
44	45	MISCELLANEOUS EXPENSE	401 - 566		1,018,264			43
45	46	RENTS	401 - 567		40,143			44
46	47	SUPERVISION AND ENGINEERING	402 - 568		403,322	6,507,322.71		45
47	48	COMPUTER HARDWARE, SOFTWARE, ETC	402 - 569		752,317			46
48	49	STATION EQUIPMENT	402 - 570		1,143,012			47
49	50	OVERHEAD SYSTEM	402 - 571		1,630,625			48
50	51	UNDERGROUND LINES	402 - 572		308			49
51	52	MAINTENANCE OF MISCELLANEOUS PLANT	402 - 573		0			50
52	53	DAY-AHEAD & REAL-TIME AND TRANSMISSION MARKET EXPENSE	401 - 575		1,435,087			51
53	54	COMPUTER SOFTWARE	402 - 576		56,085	3,995,669.49		52
54	55							53
DISTRIBUTION EXPENSE:								
55	56	OPERATION, SUPERVISION & ENGINEERING	401 - 580		522,846			54
56	57	LOAD DISPATCHING	401 - 581		295,848			55
57	58	STATION EXPENSES	401 - 582		145,438			56
58	59	LINE EXPENSES	401 - 583		330,930			57
59	60	UNDERGROUND LINE EXPENSES	401 - 584		1,099,905			58
60	61	STREETLIGHTING & SIGNAL SYSTEM	401 - 585		0			59
61	62	NOT USED	401 - 586.01		0			60
62	63	NOT USED	401 - 586.02		0			61
63	64	NOT USED	401 - 586.03		0			62
64	65	NOT USED	401 - 586.04		0			63
65	66	NOT USED	401 - 586.05		0			64
66	67	NOT USED	401 - 586.06		0			65
67	68	METER EXPENSES:	401 - 586		1,000,585			66
68	69	OTHER DISTRIBUTION EXPENSES	401 - 587		327,862			67
69	70	MISCELLANEOUS DISTRIBUTION EXPENSES	401 - 588		2,274,823			68
70	71	RENTS	401 - 589		240,965			69
71	72	MAINTENANCE, SUPERVISION & ENGINEERING	402 - 590		813,410	6,239,201.96		70
72	73	MAINTENANCE OF STATION EQUIPMENT	402 - 592		832,021			71
73	74	MAINTENANCE OF OVERHEAD LINES	402 - 593		4,537,893			72
74	75	MAINTENANCE OF UNDERGROUND LINES	402 - 594		829,638			73
75	76	MAINTENANCE OF LINE TRANSFORMERS	402 - 595		992,747			74
76	77	MAINTENANCE OF STREETLIGHTING & SIGNAL	402 - 596		441,438			75
77	78	MAINTENANCE OF METERS:	402 - 597		0			76
78	79	NOT USED	402 - 597.01		0			77
79	80	NOT USED	402 - 597.02		0			78
80	81	NOT USED	402 - 597.03		0			79
81	82	MAINTENANCE OF PROPERTY IN A/C 371	402 - 598		8,447,147.21			80
(2) Oracle GL865A FERC Trial Balance Report								

2007		FUNCTIONALIZATION		Page 3 of 6	
Line #	DESCRIPTION	ACCOUNTS	(2) STATEMENT AMOUNTS ACTUAL YEAR 2007		
1	CUSTOMER ACCOUNTING:				
2	SUPERVISION	401 - 901	192,629		
3	METER READING EXPENSES	401 - 902	4,569,617		
4	CUSTOMER RECORDS & COLLECTION EXPENSE	401 - 903	4,713,170		
5	UNCOLLECTIBLE ACCOUNTS	401 - 904	684,000		
6	MISCELLANEOUS EXPENSES	401 - 905	347,844		
7				401 = 10,507,259.66	
8	CUSTOMER SERVICE AND INFORMATION EXPENSE:				
9	SUPERVISION	401 - 907	727,164		
10					
11	CUSTOMER ASSISTANCE EXPENSES	401 - 908	1,487,537		
12	NOT USED	401 - 908.2	0		
13	NOT USED	401 - 908.3	0		
14	NOT USED	401 - 908.4	0		
15	NOT USED	401 - 908.11	0		
16	NOT USED	401 - 908.12	0		
17	NOT USED	401 - 908.13	0		
18	CONSERVATION INVESTMENT PROGRAM - SD	401 - 908.16	0		
19	CONSERVATION INVESTMENT PROGRAM - ND	401 - 908.17	0		
20	CONSERVATION INVESTMENT PROGRAM - MN	401 - 908.18	2,618,980		
21	NOT USED	401 - 908.22	0		
22	NOT USED	401 - 908.23	0		
23	INFO & INSTR ADVERTISING EXPENSE	401 - 909	327,300		
24	MISCELLANEOUS EXPENSES	401 - 910	80,719		
25				401 = 5,241,699.10	
26	SALES EXPENSES:				
27	SUPERVISORY LABOR AND EXPENSES	401 - 911	0		
28	NORTH DAKOTA ECONOMIC DEVELOPMENT	401 - 912	427,508		
29	NOT USED	401 - 912.04	0		
30	EXPENSES - SALES & DEMONSTRATIONS	401 - 912	376,182		
31	NOT USED	401 - 912.10	0		
32	NOT USED	401 - 912.11 & 12	0		
33	NOT USED	401 - 912.13	0		
34	NOT USED	401 - 912.14	0		
35	NOT USED	401 - 912.20	0		
36	NOT USED	401 - 912.21 & 22	0		
37	NOT USED	401 - 912.23	0		
38	NOT USED	401 - 912.24	0		
39	NOT USED	401 - 912.30	0		
40	NOT USED	401 - 912.32	0		
41	NOT USED	401 - 912.33	0		
42	NOT USED	401 - 912.34	0		
43	ADVERTISING	401 - 913	298,289		
44	MISCELLANEOUS SALES EXPENSE	401 - 916	318,260		
45	NOT USED	401 - 916.02	0		
46	NOT USED	401 - 916.03	0		
47	NOT USED	401 - 916.04	0		
48	NOT USED	401 - 916.08	0		
49	NOT USED	401 - 916.10	0		
50	NOT USED	401 - 916.11	0		
51	NOT USED	401 - 916.12	0		
52	NOT USED	401 - 916.13	0		
53	NOT USED	401 - 916.20	0		
54	NOT USED	401 - 916.21	0		
55	NOT USED	401 - 916.22	0		
56	NOT USED	401 - 916.23	0		
57	NOT USED	401 - 916.30	0		
58	NOT USED	401 - 916.31	0		
59	NOT USED	401 - 916.32	0		
60	NOT USED	401 - 916.33	0		
61				401 = 1,421,239.11	
62	OPERATING EXPENSES - ADMIN & GENERAL:				
63	SALARIES, OFFICE SUPPLIES & EXPENSES	401 - 920	16,802,139		
64	VARIOUS ADMIN & GENERAL EXPENSES	401 - 921	4,647,887		
65	CAPITALIZED ADMIN & GENERAL EXPENSES	401 - 922	0		
66	OUTSIDE SERVICES EMPLOYED	401 - 923	1,555,302		
67	PROPERTY TAXES	401 - 924	84,551		
68	INJURIES & DAMAGES	401 - 925	1,848,497		
69	EMPLOYEE PENSIONS & BENEFITS	401 - 926	914,010		
70	REGULATORY COMMISSION EXPENSES	401 - 928	1,931,771		
71	MISCELLANEOUS GENERAL EXPENSES	401 - 930	1,295,861		
72	INFORMATIONAL ADVERTISING	401 - 930.01	615,095		
73	RENTS	401 - 931	295,755		
74	MAINTENANCE EXPENSES	402 - 935	2,724,986		
75	RADIO LOAD CONTROL EQUIPMENT	402 - 935.06	0		

Line #		FACTORS		2007		FUNCTIONALIZATION		Line #	
BASE/PEAK SPLIT		BASE (4)		100.00%		(1) 2006 ACTUAL COSS, FUNCTIONALIZATION RUN		(4) ENTER ONLY 2 DECIMAL PLACES.	
JANUARY 2007 ACTUAL (1)		33.13%		66.87%		See Footnote 5 on C-1 for Explanation of why does not match 2006 COSS		(2) C-1, PAGE 1 OF 3 (year is correct - see description on C-1)	
JANUARY 2008 ACTUAL (2)		28.11%		71.89%		(3) SAME FORMULAS AS PRIOR YEARS FUNCTIONALIZATION RUNS		(3) SAME FORMULAS AS PRIOR YEARS FUNCTIONALIZATION RUNS	

(1) 2006 ACTUAL COSS FUNCTIONALIZATION RUN
(2) C-2, PAGE 1 OF 2

Line #	PLANT IN SERVICE	SYSTEM BALANCES		Line #
		12/31/06 (1)	12/31/07	
1	PRODUCTION PLANT			1
2	A/C 101 & 106 - BASE DEMAND	239,873,255	314,844,448	2
3	PEAK DEMAND	118,842,544	0	3
4	BASE ENERGY	0	0	4
5				5
6	SUBTOTAL A/C 101 & 106	358,715,800	437,953,050	6
7				7
8	A/C 114 - BASE DEMAND	1,062,066	1,141,706	8
9	PEAK DEMAND	526,189	446,469	9
10	BASE ENERGY	0	0	10
11				11
12	SUBTOTAL A/C 114	1,588,255	1,588,255	12
13				13
14	TOTAL PRODUCTION PLANT	360,304,054	439,541,305	14
15				15
16	TRANSMISSION PLANT			16
17	A/C 101 & 106	189,626,692	191,578,729	17
18	A/C 114	58,287	58,287	18
19				19
20	TOTAL TRANSMISSION PLANT	189,684,980	191,637,016	20
21				21
22	DISTRIBUTION PLANT - A/C 101, 106 & 114			22
23	PRIM DEM-INC A/C 114	98,883,044	103,058,244	23
24	SECONDARY DEMAND	50,157,638	53,026,216	24
25	PRIMARY CUSTOMER	56,925,279	59,370,995	25
26	SECONDARY CUSTOMER	58,152,203	61,692,818	26
27	STREETLIGHTING	11,761,736	12,216,669	27
28	AREA LIGHTING	4,406,276	4,547,052	28
29	METERS	19,437,773	19,758,102	29
30	LOAD MANAGEMENT	8,069,040	8,736,815	30
31	TOTAL DISTRIBUTION PLANT	307,792,988	322,406,912	31
32				32
33	GENERAL PLANT			33
34	PRODUCTION			34
35	TRANSMISSION	25,954,032	26,164,716	35
36	DISTRIBUTION	10,346,321	10,015,236	36
37	CUSTOMER ACCOUNTS	16,306,234	17,796,540	37
38	CUSTOMER SERVICE & INFO	12,723,422	12,723,422	38
39	LOAD MANAGEMENT	4,146,952	4,378,650	39
40		135,027	135,027	40
41				41
42	TOTAL GENERAL PLANT	69,493,744	71,215,483	42
43				43
44				44
45				45
46				46
47				47
48	OPERATING EXPENSES		AMOUNT	48
49	PRODUCTION EXPENSES			49
50	PROD EXPENSES EXCL PURCHASED POWER			50
51	BASE DEMAND		11,325,547	51
52	PEAK DEMAND		5,611,117	52
53	BASE ENERGY		62,473,643	53
54	PEAK ENERGY		6,236,150	54
55				55
56	TOTAL EXCLUDING PURCHASED POWER		85,646,457	56
57				57
58	TRANSMISSION EXPENSES		10,492,992	58
59				59
60	DISTRIBUTION EXPENSES			60
61	PRIMARY DEMAND		4,157,949	61
62	SECONDARY DEMAND		1,331,858	62
63	PRIMARY CUSTOMER		2,841,193	63
64	SECONDARY CUSTOMER		2,298,330	64
65	STREETLIGHTING		1,508,249	65
66	AREA LIGHTING		42,974	66
67	METERS		2,505,796	67
68	LOAD MANAGEMENT		0	68
69				69
70	TOTAL DISTRIBUTION		14,686,340	70

Line #		2007	FUNCTIONALIZATION	Page 6 of 6	Line #
1	CUSTOMER ACCOUNTING EXPENSES				1
2	METER READING			4,654,956	2
3	OTHER			5,852,304	3
4					4
5	TOTAL CUSTOMER ACCOUNTS			10,507,260	5
6					6
7	CUSTOMER SERV & INFO EXP - MN			2,618,980	7
8	- ND			0	8
9	- SD			0	9
10	- OTHER			2,622,720	10
11					11
12	TOTAL CUSTOMER SERV & INFORMATION EXP			5,241,699	12
13					13
14	SALES EXPENSES - MN			0	14
15	- ND			427,509	15
16	- SD			0	16
17	- OTHER			993,731	17
18					18
19	TOTAL SALES EXPENSES			1,421,239	19
20					20
21	ADMINISTRATIVE & GENERAL EXPENSES				21
22	SALARIES, SUPPLIES, PENSIONS & BENEFITS				22
23	PRODUCTION			8,158,482	23
24	TRANSMISSION			3,122,913	24
25	DISTRIBUTION			5,549,875	25
26	CUSTOMER ACCOUNTS			3,967,362	26
27	CUSTOMER SERVICE & INFO			1,365,305	27
28					28
29	TOTAL A&G SALARIES, SUPPLIES, PENSIONS & BENEFITS			22,164,036	29
30					30
31	ADMINISTRATIVE & GENERAL EXPENSES				31
32	LOAD MANAGEMENT			0	32
33	OUTSIDE SERVICES (A/C 923)			1,595,302	33
34	PROPERTY INSURANCE (A/C 924)			974,518	34
35	INJURIES & DAMAGES (A/C 925)			1,646,497	35
36					36
37	GENERAL ADVERTISING (A/C 930.1)			615,095	37
38	MISC. RENTS, MAINTENANCE			3,702,507	38

Total Expenses Pg's 5 & 6 158,693,951.33
 Total Expenses Pg's 2 & 3 160,625,722.62
 Difference (1,931,771.29)
 Less: Regulatory Commission Expense 1,931,771. (1)
 (0.06) Rounding due to Distribution Allocation Factors

(1) Regulatory Commission Expense is included in Operating Expense above and then is pulled out down below as it is treated as a separate adjustment on the Input Summary.

Volume 4A – Section 2

2007 Actual Year work papers

Input Summary

OTTER TAIL POWER COMPANY
SUMMARY OF AVERAGE RATE BASE
ACTUAL YEAR 2007

(A) SYSTEM BALANCES				(B)		(C)		(D)		(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
Line	12/31/2006	12/31/2007	AVERAGE	EMISSION ALLOWANCES	ECONOMIC DEVELOPMENT	ADVERTISING EXPENSES	Non-Asset Wholesale Expenses	WIND PROJECT COSTS	DEF TAX BIG STONE DEF OH									Line
1	(1)	(3)						(5)										1
2																		2
3	239,873,255	314,944,448	277,358,951					(23,732,362)										3
4	118,842,544	123,108,602	120,975,573					(9,279,687)										4
5		0	0															5
6																		6
7	358,715,800	437,953,050	398,334,425															7
8																		8
9	1,062,066	1,141,796	1,101,931															9
10	526,189	446,458	486,324															10
11	0	0	0															11
12																		12
13																		13
14	1,588,255	1,588,255	1,588,255															14
15																		15
16	360,304,054	439,541,305	399,922,680															16
17																		17
18	189,626,692	191,578,729	190,602,711															18
19	58,287	58,287	58,287															19
20																		20
21	189,664,990	191,637,016	190,660,998															21
22																		22
23																		23
24	98,883,044	103,058,244	100,970,644															24
25	50,157,638	53,026,216	51,591,927															25
26	56,925,279	59,370,995	58,148,137															26
27	58,152,203	61,692,818	59,922,510															27
28	11,761,736	12,216,669	11,989,203															28
29	4,406,276	4,547,052	4,476,664															29
30	19,437,773	19,758,102	19,597,938															30
31	8,069,040	8,736,815	8,402,928															31
32																		32
33																		33
34	307,792,988	322,406,912	315,099,950															34
35																		35
36	25,954,032	26,164,716	26,059,374															36
37	10,348,321	10,015,236	10,181,778															37
38	16,306,234	17,798,546	17,052,390															38
39	12,401,339	12,723,402	12,562,370															39
40	4,348,792	4,378,556	4,363,674															40
41	135,027	135,027	135,027															41
42																		42
43																		43
44	69,493,744	71,215,483	70,354,613															44
45																		45
46	3,383,281	4,086,760	3,735,021															46
47																		47
48	930,659,047	1,028,887,476	979,773,261															48

(5) ND-4, Page 1 of 2

12/31/2006

(1) Functionalization run page 5 of 6

(2) Financial Statement, p 10

12/31/2007

(3) Functionalization run page 5 of 6

(4) Financial Statement, p 10, Total EPIS minus PHFU

1,028,917,132
29,656
Difference

1,028,887,476
0

OTTER TAIL POWER COMPANY
SUMMARY OF AVERAGE RATE BASE
ACTUAL YEAR 2007

		(A) SYSTEM BALANCES		(B)	(C)		(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
		12/31/2006	12/31/2007		AVERAGE	EMISSION ALLOWANCES	ECONOMIC DEVELOPMENT	ADVERTISING EXPENSES	Non-Asset Wholesale Expenses	WIND PROJECT COSTS	DEF TAX BIG STONE DEF OH					Line
1	2	(1)	(2)							(6)						1
2	3															2
3	4															3
ACCUMULATED DEPRECIATION																4
PRODUCTION PLANT																5
BASE DEMAND - MN		(65,974,636)	(81,432,068)		(73,703,352)											(73,703,352)
- ND		(50,461,715)	(62,112,234)		(56,286,975)											(56,286,975)
- SD		(9,603,382)	(11,897,085)		(10,750,233)											(10,750,233)
- FERC		(157,525)	(281,800)		(219,662)											(219,662)
PEAK DEMAND - MN		(46,430,413)	(31,846,609)		(39,139,511)											(39,139,511)
- ND		(35,513,016)	(24,292,497)		(29,902,796)											(29,902,796)
- SD		(6,758,491)	(4,653,027)		(5,705,799)											(5,705,799)
- FERC		(110,860)	(110,214)		(110,537)											(110,537)
BASE ENERGY - MN		0	0		0											0
- ND		0	0		0											0
- SD		0	0		0											0
- FERC		0	0		0											0
TOTAL PRODUCTION PLANT		(215,010,037)	(216,627,534)		(215,818,786)	0	0	0	0		0					(215,818,786)
TRANSMISSION PLANT - MN		(3)	(4)													19
- ND		(38,005,310)	(39,878,229)		(38,941,770)											(38,941,770)
- SD		(30,001,845)	(31,391,037)		(30,696,441)											(30,696,441)
- FERC		(5,836,922)	(6,138,673)		(5,987,798)											(5,987,798)
TOTAL TRANSMISSION PLANT		(745,226)	(785,404)		(765,315)											(765,315)
DISTRIBUTION PLANT - MN		(74,589,303)	(78,193,343)		(76,391,323)	0	0	0	0		0					(76,391,323)
- ND		(58,245,149)	(61,115,390)		(59,680,270)											(59,680,270)
- SD		(57,911,609)	(60,718,928)		(59,315,268)											(59,315,268)
- FERC		(12,064,672)	(12,685,954)		(12,375,313)											(12,375,313)
TOTAL DISTRIBUTION PLANT		(343,491)	(412,633)		(378,062)											(378,062)
GENERAL PLANT - MN		(128,564,921)	(134,932,905)		(131,748,913)	0	0	0	0		0					(131,748,913)
- ND		(14,004,882)	(14,635,200)		(14,320,041)											(14,320,041)
- SD		(11,635,677)	(11,923,971)		(11,779,824)											(11,779,824)
- FERC		(2,430,326)	(2,526,323)		(2,478,324)											(2,478,324)
TOTAL GENERAL PLANT		(66,407)	(72,564)		(69,485)											(69,485)
INTANGIBLE PLANT		(28,137,292)	(29,158,058)		(28,647,675)	0	0	0	0		0					(28,647,675)
TOTAL ACCUMULATED DEPRECIATION		(1,020,162)	(985,886)		(1,003,024)											(1,003,024)
BSP CAPITALIZED ITEMS - A/C 186		(447,321,715)	(459,897,725)		(453,609,720)	0	0	0	0		0					(453,609,720)
A/C 186 - MN		(5)	(5)													
A/C 186 - ND		0	0		0											0
A/C 186 - SD		138,973	98,298		118,635											118,635
A/C 186 - FERC		12,552	8,878		10,715											10,715
TOTAL BSP CAP ITEMS - A/C 186		151,525	107,176		129,351	0	0	0	0		0					129,351
TOTAL NET PLANT IN SERVICE		483,488,857	569,096,926		526,292,892	0	0	0	0		0					483,280,843

(1) A-1, PAGE 1 OF 2 actual COSS 2006
(2) A-1, PAGE 1 OF 2 actual COSS 2007
(3) A-1, PAGE 2 OF 2 actual COSS 2006
(4) A-1, PAGE 2 OF 2 actual COSS 2007
(5) B-8, PAGE 1 OF 2

ARC Amortization
Transferred to Regulatory Liability
+ Unclass saliv of
F/S Accumulated Prov. For Depr & A

185,232
(13,295,373)
(312,141)

446,475,444
Agrees to F/S Accumulated Prov. For Depr. and Amort. (Page 2 of F/S)

0

(6) ND-4, Page 1 of 2

OTTER TAIL POWER COMPANY
SUMMARY OF AVERAGE RATE BASE
ACTUAL YEAR 2007

NORTH DAKOTA

A-SUMMARY
PAGE 3 OF 5

(A) SYSTEM BALANCES																									(B)		(C)		(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																													
																									12/31/2006		12/31/2007		AVERAGE	EMISSION ALLOWANCES	ECONOMIC DEVELOPMENT	ADVERTISING EXPENSES	Non-Asset Wholesale Expenses	WIND PROJECT COSTS	DEF TAX BIG STONE DEF OH							TOTAL	Line																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																								
1	(1)		(1)		(1)		(1)		0	0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0		0	

Line	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	Line
1													TOTAL	1
2														2
3		(1)	18,823,676										18,823,676	3
4		(1)	17,275,360										17,275,360	4
5		(1)	4,261,508										4,261,508	5
6		(1)	36,458										36,458	6
7	New Numbers	(8)	0,91767										0,91767	7
8	New Numbers	(8)	0,08233										0,08233	8
9	New Numbers	(8)	38.1										38.1	9
10	New Numbers	(8)	43.1										43.1	10
11	New Numbers	(8)	97.3										97.3	11
12	New Numbers	(8)	127.8										127.8	12
13	New Numbers	(8)	112.4										112.4	13
14	New Numbers	(8)	110.8										110.8	14
15	New Numbers	(8)	25.4										25.4	15
16	New Numbers	(8)	(86.4)										-86.4	16
17	New Numbers	(8)	35.0										35.0	17
18	New Numbers	(8)	53.2										53.2	18
19	New Numbers	(8)	37.8										37.8	19
20	New Numbers	(8)	33.6										33.6	20
21		(2)	53,130,116										53,130,116	21
22		(2)	7,351,578										7,351,578	22
23		(9)	60,090,369										60,090,369	23
25		(3)	0,919902										0,919902	25
26		(3)	0,080098										0,08010	26
27	New Numbers	(8)	16.0										16.0	27
28	New Numbers	(8)	8.9										8.9	28
29	New Numbers	(8)	32.8										32.8	29
30	New Numbers	(8)	13.9										13.9	30
31	New Numbers	(8)	19.4										19.4	31
32	New Numbers	(8)	338.9										338.9	32
33	New Numbers	(8)	241.5										241.5	33
34	New Numbers	(8)	371.5										371.5	34
35	New Numbers	(8)	314.6										314.6	35
36	New Numbers	(8)	37.1										37.1	36
37	New Numbers	(8)	43.9										43.9	37
38	New Numbers	(8)	43.9										43.9	38
39	New Numbers	(8)	20.7										20.7	39
40	New Numbers	(8)	73.0										73.0	40
41		(4)	9,400										9,400	41
42		(5)	789,085										789,085	42
43		(6)	22,679										22,679	43
44		(7)	(3,986,989)										(3,986,989)	44
45		(7)	(6,820,822)										(6,820,822)	45
46		(7)	(1,635,219)										(1,635,219)	46
47		(7)	(256,507)										(256,507)	47
48		(7)	(5,813,859)										(5,813,859)	48
49		(7)	(2,020)										(2,020)	49
50		(7)	(1,212,766)										(1,212,766)	50
51		(7)	(722,428)										(722,428)	51
52	New Numbers	(8)	0.0										0.0	52
53	New Numbers	(8)	0.0										0.0	53
54	New Numbers	(8)	1.9										1.9	54
55	New Numbers	(8)	61.1										61.1	55
56	New Numbers	(8)	15.5										15.5	56
57	New Numbers	(8)	26.1										26.1	57
58	New Numbers	(8)	16.3										16.3	58
59	New Numbers	(8)	35.2										35.2	59
60		(10)	0,3157										0,3157	60
61		(10)	0,0980										0,0980	61
62		(10)	0,3272										0,3272	62
63		(10)	0,0650										0,0650	63
64		(10)	0,3500										0,3500	64
65		(10)	0,0000										0,0000	65
66		(10)	0,3280										0,3280	66
67		(10)	0,0370										0,0370	67
68		(10)	0,0250										0,0250	68

batch total 141,329,982

NORTH DAKOTA

OTTER TAIL POWER COMPANY
OPERATING SUMMARY
ACTUAL YEAR 2007

B-SUMMARY
PAGE 1 OF 7

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
		AMOUNT	EMISSION ALLOWANCES (5)	ECONOMIC DEVELOPMENT	ADVERTISING EXPENSES	Non-Asset Wholesale Expenses	WIND PROJECT COSTS	DEF TAX BIG STONE DEF OH				TOTAL
Line												Line
1	OPERATING REVENUES	(1)										1
2	SALES OF ELECTRICITY - MN	134,836,006										2
3	- ND	108,472,410										3
4	- SD	25,389,754										4
5	- FERC	0										5
6												6
7	TOTAL RETAIL SALES	268,698,170	0	0	0	0		0				7
8												8
9	OTHER OPERATING REVENUES	(2)										9
10	SALES FOR RESALE											10
11	MUNICIPALITIES											11
12	MINNESOTA	190,431										12
13	SOUTH DAKOTA	21,001										13
14												14
15	NONASSOC, CO-OPS & OPA											15
16	ASSET-BASED WHOLESAL											16
17	ALL OTHER TRANSACTIONS	0										17
18	BASE DEMAND	0										18
19	PEAK DEMAND	0										19
20	BASE ENERGY	20,133,608										20
21	PEAK ENERGY	0										21
22												22
23	TOTAL OTHER SALES FOR RESALE	20,345,040	0	0	0	0		0				23
24												24
25	OTHER ELECTRIC REVENUES	(3)										25
26	A/C 450 FORFEITED DISCOUNTS - MN	294,443										26
27	- ND	170,779										27
28	- SD	80,104										28
29	A/C 451 CONNECTION FEES - MN	190,817										29
30	- ND	89,754										30
31	- SD	35,174										31
32	RENT FROM ELECTRIC PROPERTY	644,002										32
33	RENT FROM ELECTRIC PROPERTY - BIG STONE	(20,657)										33
34	RENT FROM ELECTRIC PROPERTY - COYOTE	11,846										34
35	OTHER MISCELLANEOUS ELECTRIC REVENUE	2,589,668	129,650									35
36	INTEGRATED TRANSMISSION DEFICIENCY PAYMENTS	3,651,858										36
37												37
38	MISCELLANEOUS SERVICES	34,025										38
39	WHEELING - MN	207,195										39
40	WHEELING - ND	216,350										40
41	WHEELING - SD	9,518										41
42	LOAD CONTROL & DISPATCHING, MAPP & MISO	4,459,926										42
43	LOAN POOL INTEREST											43
44	MINNESOTA	66,381										44
45	NORTH DAKOTA	9,642										45
46	SOUTH DAKOTA	872										46
47												47
48	TOTAL OTHER ELECTRIC REVENUES	12,741,656	129,650	0	0	0		0				48
49												49
50	TOTAL OTHER OPERATING REVENUES	33,086,696	129,650	0	0	0		0				50
51												51
52	TOTAL OPERATING REVENUES (4)	301,784,866	129,650	0	0	0		0				52

(4) F/S, Elec Op Revenue =
Provision for Customer Refunds 309,903,774 FERC 309,903,774
Meter Error Adj 1,297,930 1,297,930
Plus Interest on loan pools 0
Less COE accrual (1450...) 76,895 (8,717,024)
MN Schedule 16 & 17 Ref Rec'ble (407,010) (407,010)
ND Schedule 16 & 17 Ref Rec'ble (369,698) (369,698)
Wheeling adjustment (from B-3) 0
301,784,867 301,784,867

(1) B-1, PAGE 1 OF 2
(2) B-2, PAGE 1 OF 1
(3) B-3, PAGE 1 OF 5

(5) B-3, PAGE 1 OF 5, treated as non-operating gain on F/S adjustment reclassifies from credit to production expense to other misc revenue
Difference from above 0 0

OTTER TAIL POWER COMPANY
OPERATING SUMMARY
ACTUAL YEAR 2007

NORTH DAKOTA

B-SUMMARY
PAGE 2 OF 7

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
Line		AMOUNT	EMISSION ALLOWANCES (6)	ECONOMIC DEVELOPMENT	ADVERTISING EXPENSES	Non-Asset Wholesale Expenses (4)	WIND PROJECT COSTS	DEF TAX BIG STONE DEF OH				TOTAL
1	OPERATING EXPENSES											1
2	PRODUCTION EXPENSES	(1)										2
3	PROD EXPENSES EXCL PURCHASED POWER	11,325,547										3
4	BASE DEMAND	5,611,117				(\$1,117,334)						4
5	PEAK DEMAND	62,473,643				(\$553,623)						5
6	BASE ENERGY	6,236,150										6
7	PEAK ENERGY											7
8	TOTAL EXCLUDING PURCHASED POWER	85,646,457	0	0	0	(1,670,957)		0				8
9												9
10	PURCHASED POWER	(2)										10
11												11
12												12
13												13
14	BASE DEMAND	3,963,752										14
15	PEAK DEMAND	0										15
16	BASE ENERGY	72,263,300	129,650									16
17	PEAK ENERGY	0										17
18	TOTAL ALL OTHER TRANSACTIONS	76,227,052	129,650	0	0	0		0				18
19												19
20												20
21	TOTAL PURCHASED POWER	76,227,052	129,650	0	0	0		0				21
22												22
23	TOTAL PRODUCTION EXPENSES	161,873,509	129,650	0	0	(1,670,957)		0				23
24		(1)										24
25	TRANSMISSION EXPENSES	10,492,992				0						25
26												26
27	DISTRIBUTION EXPENSES											27
28	PRIMARY DEMAND	4,157,949										28
29	SECONDARY DEMAND	1,331,858										29
30	PRIMARY CUSTOMER	2,841,193										30
31	SECONDARY CUSTOMER	2,298,330										31
32	STREETLIGHTING	1,508,249										32
33	AREA LIGHTING	42,974										33
34	METERS	2,505,796										34
35	LOAD MANAGEMENT	0										35
36	TOTAL DISTRIBUTION	14,686,349	0	0	0	0		0				36
37												37
38	CUSTOMER ACCOUNTING EXPENSES											38
39	METER READING	4,654,956										39
40	OTHER	5,852,304										40
41												41
42	TOTAL CUSTOMER ACCOUNTS	10,507,260	0	0	0	0		0				42
43												43
44	CUSTOMER SERV & INFO EXP - (MN CIP)	2,618,980			0							44
45	- ND	0			0							45
46	- SD	0										46
47	- OTHER	2,622,720										47
48	TOTAL CUSTOMER SERV & INFORMATION EXP	5,241,699	0	0	0	0		0				48
49												49
50												50

- (1) FUNCTIONALIZATION RUNS 12/31/2007
 (2) B-4, PAGE 1 OF 5
 (3) not used
 (4) B-15 Page 1 of 6
- (5) Not Used
 (6) Adjustment removes credit to account 555 on the FERC F/S and moves it to a revenue credit B summary p 1 of 7 line 35

NORTH DAKOTA

OTTER TAIL POWER COMPANY
OPERATING SUMMARY
ACTUAL YEAR 2007

B-SUMMARY
PAGE 3 OF 7

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			AMOUNT	EMISSION ALLOWANCES (7)	ECONOMIC DEVELOPMENT (4)	ADVERTISING EXPENSES (5)	Non-Asset Wholesale Expenses (8)	WIND PROJECT COSTS	DEF TAX BIG STONE DEF OH				TOTAL
Line													Line
1	ADMINISTRATIVE & GENERAL EXPENSES - (CONTINUED)		(1)	0	198,119								1
2	SALES EXPENSES - MN												2
3	- ND		427,508										3
4	- SD		0		38,078								4
5	- OTHER		993,731		(236,197)	(299,269)							5
6													6
7	TOTAL SALES EXPENSES		1,421,239	0	0	(299,269)	0		0				7
8													8
9	ADMINISTRATIVE & GENERAL EXPENSES												9
10	SALARIES, SUPPLIES, PENSIONS & BENEFITS												10
11	PRODUCTION												11
12	TRANSMISSION		8,158,582				(48)						12
13	DISTRIBUTION		3,122,913				(32)						13
14	CUSTOMER ACCOUNTS		5,549,875				(23)						14
15	CUSTOMER SERVICE & INFO		3,967,362				(8)						15
16			1,365,305										16
17	TOTAL A&G SALARIES, SUPP, PENSIONS & BENEFITS		22,164,036	0	0	0	(129)		0				17
18													18
19	ADMINISTRATIVE & GENERAL EXPENSES												19
20	LOAD MANAGEMENT		0										20
21	OUTSIDE SERVICES (A/C 923)		1,595,302										21
22	PROPERTY INSURANCE (A/C 924)		974,518										22
23	INJURIES & DAMAGES (A/C 925)		1,646,497										23
24			(2)										24
25	REGULATORY COMM EXP (A/C 928)-MN		1,408,318										25
26	-ND		96,703										26
27	-SD		41,863										27
28	-FERC		205,243										28
29													29
30	TOTAL REGULATORY COMMISSION EXPENSE		1,752,128	0	0	0	0		0				30
31	GENERAL ADVERTISING (A/C 930.1)	(1)	615,095			(613,716)	0						31
32	MISC, RENTS, MAINTENANCE	(1)	3,702,507			1,578	0						32
33													33
34	TOTAL ADMINISTRATIVE & GENERAL EXPENSE		32,450,082	0	0	(612,139)	(129)		0				34
35													35
36	CHARITABLE CONTRIBUTIONS (& CUST DEP INTEREST)		(3)										36
37	MINNESOTA ONLY		111,967										37
38	NORTH DAKOTA ONLY		0										38
39	SOUTH DAKOTA ONLY		0										39
40													40
41	TOTAL CHARITABLE CONTRIBUTIONS (& CUST DEP INT		111,967	0	0	0	0		0				41
42													42
43													43
44	TOTAL O & M EXPENSES (6)		236,785,098	129,650	0	(911,427)	(1,671,087)		0				44

(1) FUNCTIONALIZATION RUNS 12/31/2007

(2) B-5, PAGE 1 OF 2

(3) B-6, PAGE 1 OF 2

(4) B-13, Page 1 of 2

(5) B-14, page 1 of 2

(6) F/S (FERC)

Plus donations

Removed from account 928

Gain on sale of emission allow (7)

Accrued interchange energy

Total

Difference from line 44 above

(7) Gain on sale of emission allowances treated as expense, FERC requires to be income.

(8) B-15 Page 1 of 6 total adjustment.

0

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			AMOUNT	EMISSION ALLOWANCES	ECONOMIC DEVELOPMENT	ADVERTISING EXPENSES	Non-Asset Wholesale Expenses	WIND PROJECT COSTS	DEF TAX BIG STONE DEF OH				TOTAL
Line			(1)					(5)					
1	DEPRECIATION EXPENSE												
2	PRODUCTION PLANT												
3	BASE DEMAND - MN		3,534,759										3,534,759
4	- ND		2,549,090										2,549,090
5	- SD		567,254										567,254
6	- FERC		6,962										6,962
7	PEAK DEMAND - MN		1,382,467										1,382,467
8	- ND		996,966										996,966
9	- SD		221,857										221,857
10	- FERC		2,723										2,723
11	BASE ENERGY - MN		0										0
12	- ND		0										0
13	- SD		0										0
14	- FERC		0										0
15	TOTAL PRODUCTION PLANT		9,262,078	0	0	0	0		0				9,262,078
16													
17	TRANSMISSION PLANT - MN												
18	- ND		2,048,582										2,048,582
19	- SD		1,527,896										1,527,896
20	- FERC		328,726										328,726
21			42,536										42,536
22	TOTAL TRANSMISSION PLANT												
23			3,947,740	0	0	0	0		0				3,947,740
24													
25	DISTRIBUTION PLANT - MN												
26	- ND		3,985,561										3,985,561
27	- SD		3,918,044										3,918,044
28	- FERC		850,943										850,943
29			21,444										21,444
30	TOTAL DISTRIBUTION PLANT												
31			8,775,992	0	0	0	0		0				8,775,992
32	GENERAL PLANT - MN												
33	- ND		1,212,572										1,212,572
34	- SD		1,002,568										1,002,568
35	- FERC		218,332										218,332
36			6,309										6,309
37	TOTAL GENERAL PLANT												
38			2,439,781	0	0	0	0		0				2,439,781
39	INTANGIBLE PLANT												
40			410,801										410,801
41	TOTAL DEPRECIATION EXPENSE (4)		24,836,391	0	0	0	0		0				24,836,391

(1) B-7, PAGE 1 OF 2

(2) B-7, PAGE 2 OF 2

(4) FERC F/S, p. 5 =

Difference from above

24,836,391

(0)

(5) ND-4, Page 2 of 2

OTTER TAIL POWER COMPANY
OPERATING SUMMARY
ACTUAL YEAR 2007

NORTH DAKOTA

B-SUMMARY
PAGE 5 OF 7

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
		AMOUNT	EMISSION ALLOWANCES	ECONOMIC DEVELOPMENT	ADVERTISING EXPENSES	Non-Asset Wholesale Expenses	WIND PROJECT COSTS	DEF TAX BIG STONE DEF OH				TOTAL
Line												Line
1	BIG STONE EXPENSE OFFSETS	(1)						(7)				1
2	MINNESOTA											2
3	NORTH DAKOTA	0										3
4	SOUTH DAKOTA	0										4
5	FERC	0										5
6												6
7	TOTAL BIG STONE EXPENSE OFFSETS	0	0	0	0	0	0	0				7
8	SPRITWOOD AMORTIZATION	(2)										8
9	MINNESOTA	0										9
10	NORTH DAKOTA	0										10
11	SOUTH DAKOTA	0										11
12	FERC	0										12
13												13
14	TOTAL SPRITWOOD AMORTIZATION	0	0	0	0	0	0	0				14
15	GENERAL TAXES	(3)										15
16		9,411,607										16
17	TOTAL OPERATING EXPENSE BEFORE TAX											17
18		271,033,097	129,650	0	(911,427)	(1,671,087)		0				18
19	NET OPERATING INCOME BEFORE TAX											19
20		30,751,770	0	0	911,427	1,671,087		0				20
21												21
22	INVESTMENT TAX CREDIT	(4)										22
23	AMORTIZATION OF PRIOR YEARS' CREDIT	(1,136,657)										23
24	DEBITS UTILIZED	0										24
25												25
26	TOTAL INVESTMENT TAX CREDIT	(1,136,657)	0	0	0	0		0				26
27												27
28	DEFERRED INCOME TAXES	(5)										28
29	ITEMS SD FLOWS THROUGH											29
30	FEDERAL	587,347										30
31	MINNESOTA	68,662										31
32	NORTH DAKOTA	53,223										32
33												33
34	SUBTOTAL	709,232	0	0	0	0		0				34
35	ALL OTHER											35
36	FEDERAL	(248,300)						(12,084)				36
37	MINNESOTA	32,023						(1,424)				37
38	NORTH DAKOTA	(1,524)						(13,509)				38
39												39
40	SUBTOTAL	(217,801)	0	0	0	0		(13,509)				40
41												41
42	TOTAL DEFERRED INCOME TAXES	491,431	0	0	0	0		(13,509)				42
43												43
44	ALLOWANCE FOR FUNDS USED DURING CONST	2,257,062										44

(1) B-8, PAGE 1 OF 2; expense is included in Depreciation Expense

(2) B-9, PAGE 1 OF 2

(3) FINANCIAL STATEMENT, PAGE 5

(4) B-10, PAGE 1 OF 3

(5) A-5, PAGE 3 OF 5

(6) FERC a/c 432 (debit)

(6) FERC 419.1 (equity)

(7) ND-1, PAGE 2 of 3

(8) Found on Monthly FERC F/S

2,275,656 (8)
(18,594) (8)

0

OTTER TAIL POWER COMPANY
OPERATING SUMMARY
ACTUAL YEAR 2007

NORTH DAKOTA

B-SUMMARY
PAGE 6 OF 7

Line	(A)	(B)	(C) AMOUNT	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M) TOTAL	Line
1													2,701,294	1
2		(6)	2,701,294										2,701,294	2
3		(6)	3,949,203										3,949,203	3
4														4
5		(2)	(26,138)										(26,138)	5
6		(2)	(59,233)										(59,233)	6
7		(2)	(7,848)										(7,848)	7
8		(2)	(67)										(67)	8
9		(1)	87,932										87,932	9
10		(7)	4,671,807										4,671,807	10
11		(7)	(8,598,414)										(8,598,414)	11
12		(1)											0	12
13		(6)	160,775										160,775	13
14		(3)	(1,606,800)										(1,606,800)	14
15		(6)											0	15
16		(4)	(4,946,621)										(4,946,621)	16
17		(4)											0	17
18		(3)	940,583										940,583	18
19		(4)	(18,508)										(18,508)	19
20		(4)											0	20
21		(4)											0	21
22		(3)	(9,000)										(9,000)	22
23		(5)	35,00%										35,00%	23
24		(5)	9.8%										9.8%	24
25		(5)	6.5%										6.5%	25
26		(5)	1,705,611										1,705,611	26
27		(5)	1,645,413										1,645,413	27
28		(5)	1,540,773										1,540,773	28
29		(5)	1,639,344										1,639,344	29
INCOME TAX CALCULATION ITEMS:														
ADDITIONAL TAX DEPRECIATION														
COST OF REMOVAL														
DIRECTLY ASSIGNED SCHEDULE M														
MINNESOTA														
NORTH DAKOTA														
SOUTH DAKOTA														
FERC														
ACCURED VACATION PAY														
CHARGES - OPERATING RESERVES														
PROVISIONS - OPERATING RESERVES														
PREFERRED DIVIDENDS PAID CREDIT														
OTHER MAJOR SCHEDULE M ITEMS														
CHANGE IN EXCESS TAX DEPRECIATION - MN														
MISCELLANEOUS ADJUSTMENTS TO FEDERAL AOIBT - MN														
CHANGE IN EXCESS TAX DEPRECIATION - ND														
MISCELLANEOUS ADJUSTMENTS TO FEDERAL AOIBT - ND														
FEDERAL TAX RATE														
MINNESOTA TAX RATE														
NORTH DAKOTA TAX RATE														
MINNESOTA TAX RATE														
MINNESOTA CONVERSION FACTOR														
NORTH DAKOTA CONVERSION FACTOR														
SOUTH DAKOTA CONVERSION FACTOR														
SERC CONVERSION FACTOR														

- (1) B-12, PAGE 1 OF 9
(2) B-12, PAGE 7 OF 9
(3) B-12, PAGE 6 OF 9
(4) B-12, PAGE 8 OF 9
(5) C-4, PAGE 1 OF 2
(6) B-12, PAGE 2 OF 9
(7) B-12, PAGE 4 OF 9

**OTTER TAIL POWER COMPANY
OPERATING SUMMARY
ACTUAL YEAR 2007**

NORTH DAKOTA

**B-SUMMARY
PAGE 7 OF 7**

(M)

(L)

(K)

(J)

(I)

(H)

(G)

(F)

(E)

(D)

(C)

(B)

(A)

SALES OF ELECTRICITY	BY CLASS	W/O UNBILLED*	UNBILLED		(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			% OF TOTAL	UNBILLED									
RESIDENTIAL	36,335,353	36,265,250	33.497%	70,103									
FARMS	1,594,054	1,590,979	1.470%	3,075									
GENERAL SERVICE	33,833,612	33,768,335	31.191%	65,276									
LARGE GENERAL SERVICE	26,835,622	26,783,847	24.740%	51,775									
IRRIGATION	45,763	45,674	0.042%	88									
OUTDOOR LIGHTING	2,095,756	2,091,712	1.932%	4,043									
OPA	963,556	961,697	0.888%	1,859									
CONTROLLED WATER HEATING	1,179,460	1,177,185	1.087%	2,276									
CONTROLLED SERVICE INTERRUPT	4,746,377	4,737,220	4.376%	9,157									
CONTROLLED SERVICE DEFERRED	842,857	841,231	0.777%	1,626									
TOTAL	108,472,410	108,263,131	100.000%	209,279	Unbilled (5)								
* Amounts are customer classes; Stat Book uses revenue classes.													
FACTORS			TOTAL	MN	ND	SD	FERC	CLASS TOTAL	RESIDENTIAL	FARMS	GENERAL SERVICE		LARGE GENERAL SERVICE
(1)	OK	D1	596,234	304,929	236,559	55,954	792	236,559	83,948	4,282	78,714	58,200	
(1)	OK	D2	604,225	304,929	236,559	55,954	6,783	236,559	83,948	4,282	78,714	58,200	
(1)	OK	D3	757,342	340,610	332,687	77,778	6,267	332,687	81,375	6,402	90,235	69,378	
(1)	OK	D4	998,227	432,549	459,319	106,359	-	459,319	111,558	12,711	124,762	61,432	
(1)	OK	E1	3,918,074	2,074,148	1,457,625	382,540	3,761	1,457,625	432,402	24,607	448,292	491,634	
(1)	OK	E2	4,430,839	2,277,133	1,720,495	429,450	3,761	1,720,495	490,575	25,529	451,012	491,634	
(1)	OK	C1	129,675	60,947	57,014	11,714	-	57,014	44,201	916	10,870	123	
(1)	OK	C2	135,857	63,959	59,913	12,381	4	59,913	46,011	1,091	11,860	140	
(1)	OK	C3	135,784	63,511	59,901	12,372	-	59,901	46,011	1,091	11,876	132	
(1)	OK	C4	4,185,546	1,980,427	1,760,035	445,084	-	1,760,035	-	-	-	0	
(1)	OK	C5	3,688,552	1,621,835	1,716,671	350,046	-	1,716,671	-	-	-	0	
(1)	OK	C6	29,240,646	13,664,904	12,850,789	2,724,953	-	12,850,789	4,439,962	328,536	3,681,789	180,785	
(1)	OK	C7	173,474	84,014	73,215	16,245	-	73,215	45,597	943	18,374	305	
(1)	OK	C8	135,879	63,581	59,913	12,381	4	59,913	46,011	1,091	11,880	140	
(1)	OK	C9	40,923	18,775	18,040	4,108	-	18,040	3,722	42	38	0	
LONG TERM DEBT - AMOUNT (Includes S-T Debt)			IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED					
(1)	D1		0	2,305	2,939	346	5,237	588					
(1)	D2		1,096	2,305	2,939	346	5,237	588					
(1)	D3		1,550	6,007	2,797	10,010	57,405	7,962					
(1)	D4		-	5,774	3,821	30,451	94,738	12,522					
(1)	E1		-	24,702	18,381	8,940	-	8,667					
(1)	E2		712	24,702	18,381	21,459	175,691	20,800					
(1)	C1		27	26	545	18	225	36					
(1)	C2		69	33	572	18	85	14					
(1)	C3		69	33	572	18	85	14					
(1)	C4		-	1,760,035	-	-	-	-					
(1)	C5		-	1,716,671	-	-	-	-					
(1)	C6		51,098	10,464	159,285	1,908,048	1,848,130	242,692					
(1)	C7		37	30	624	3,790	3,130	385					
(1)	C8		69	33	572	18	85	14					
(1)	C9		19	-	-	7,564	6,036	619					
(2)			185,725,713										
(3)			15,500,000										
(4)			229,633,133										
(2)			0.0630										
(3)			0.0475										
(6)			0.1200										

(4) D-3, PAGE 1 OF 1
(5) B-1, Pages 1 & 2 and report from Dean Hjelte
(6) Allowed ROE under ND PBR

(1) C-3, PAGE 2 OF 3
(2) D-1, PAGE 1 OF 2
(3) D-2, PAGE 1 OF 1

Volume 4A – Section 2

2007 Actual Year work papers

Work papers A-D

North Dakota COSS Workpapers

A - 1	Accumulated Depreciation
A - 2	CWIP
A - 3	Materials & Supplies
A - 4	Prepayments
A - 5	Accum Deferred Income Tax
A - 6	Customer Advances
A - 7	Cash Working Capital
A - 8	Fuel Stocks
B - 1	Retail Revenue
B - 2	Sales For Resale
B - 3	Other Electric Revenue
B - 4	Purchased Power
B - 5	Regulatory Commission Expense
B - 6	Charitable Contributions
B - 7	Depreciation Expense
B - 8	Big Stone Capitalized Costs
B - 9	Spiritwood
B - 10	ITC
B - 11	N/A
B - 12	Schedule M
B - 13	Economic Development Adjustment
B - 14	Advertising Expense
B - 15	Power Services Expense
C - 1	Base/Peak Demand
C - 2	Labor Ratios
C - 3	Factors
C - 4	Effective Tax Rates
D - 1	Cost of Debt Capital
D - 2	Cost of Preferred Stock
D - 3	Common Equity
ND - 1	Def Tax-Big Stone Costs-Land
ND - 4	Removal of Wind Project Costs

Prepared By: kas
Reviewed By: pjb

Otter Tail Power Company
Accumulated Depreciation - Production
Actual Year Ending December 31, 2007

	(A)	(B)	(C)	(D)	(E)	(F)
Line No	Reserve Balances December 31, 2007	Minnesota	North Dakota	South Dakota	FERC	Total
1	Total Production (1)	112,911,484	86,127,814	16,495,529	391,192	215,926,018
2	Plus: Hydro Licensing (1)	369,193	276,918	54,583	822	701,516
3	Less: Unit Train (Base Energy) (1)	0	0	0	0	0
4	Total Demand	113,280,677	86,404,731	16,550,112	392,014	216,627,534
5	Base Demand (3)	81,432,068	62,112,234	11,897,085	281,800	155,723,187
6	Peak Demand (2)	31,848,609	24,292,497	4,653,027	110,214	60,904,347
7	Base Energy (1)	0	0	0	0	0
8	Total Production	113,280,677	86,404,731	16,550,112	392,014	216,627,534

- (1) W/P A-1, Page 2 of 4
 (2) Total Demand X Peak Demand Factor 28.11% (4)
 (3) Total Demand X Base Demand Factor 71.89% (4)
 (4) W/P, C-1, Page 1 of 3; use appropriate factors for year end balances on this worksheet

Prepared By: kas
Reviewed By: pjb

Otter Tail Power Company
Jurisdictional Depreciation Information
Actual Year Ending December 31, 2007

Line No	(A)	(B)	(C)	(D)	(E)	(F)
		(4)(a)	(4)(a)	(4)(a)	(4)(a)	
	Reserve Balances December 31, 2007	Minnesota	North Dakota	South Dakota	FERC	Total
1	Steam (Excl Unit Train & Ort)	105,717,869	80,485,518	15,377,751	373,834	201,954,972
2	Hydro	935,556	701,726	138,316	2,084	1,777,683
3	I.C & Other	6,258,060	4,940,569	979,462	15,274	12,193,364
4	Unit Train					0
5	Ortonville					0
6	Total Production	112,911,484	86,127,814	16,495,529	391,192	215,926,018
7	Transmission	39,878,229	31,391,037	6,138,673	785,404	78,193,343
8	Distribution	61,115,390	60,718,928	12,685,954	412,633	134,932,905
9	General (Exlc Transp 392)	7,679,019	6,569,200	1,356,455	34,147	15,638,821
10	Transportation (Incl Plane) (1)	6,956,182	5,354,771	1,169,867	38,417	13,519,237
11	Total General	14,635,200	11,923,971	2,526,323	72,564	29,158,058
12	Total A/C 108 & 115	228,540,303	190,161,749	37,846,478	1,661,792	458,210,323
13	<u>Intangible</u>					
14	Computer Software					985,886
15	Hydro Licensing (2)	369,193	276,918	54,583	822	701,516
16	Total A/C 108,111,&115 (Excl 108.99) (3)					459,897,725

- (1) Spread to jurisdiction on P90 factor from 2006COSS (Latest Available). Each state's separate COSS run for P90 Factor(page 16-1) FERC = difference to reach 100%.

17	MN	51.453954%
18	ND	39.608527%
19	SD	8.653354%
20	FERC	0.284165%
21		100.000000%

- (2) Spread using same proportion as Hydro

- (3) Agrees with Accumulated Depreciation excluding Unclassified Salvage/Removal, F/S December 2007

22	Monthly Statement.	Above	459,897,725	
23		ARC Amortization (4)(a)	185,232	
24		Transferred to Regulatory Liability (4)(b)	(13,295,373)	
25		Unclass Salv/CTR (4)(c)	(312,141)	
26		Agrees to F/S	446,475,444	
27		F/S Accumulated Depr. And Amort	446,475,444	0

- (4) (a) Oracle acct 1786.3170; FERC acct 10801
(b) Oracle acct 2510.1500; FERC acct 25400, excluding "initial implementation cumulative effect adj" for \$977,886, \$1,263,607 yr-end bal less \$285,721 adj for prior yr error as noted on W/P of L Demmer, tab "ARO & Related" tab.
(c) per W/P from L Demmer "Depr for cost of serv study 2007"; "Total for Reg Purposes" tab

Otter Tail Power Company
CWIP
Actual 12 Months Ending 12/31/07

Prepared by: kas
Reviewed by: pjb

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.		Actual Balance 12/31/2006	Remove Reimbursable CWIP	Adjusted Balance 12/31/06	Actual Balance 12/31/2007	Remove Reimbursable CWIP	Adjusted Balance 12/31/07
	Short Term Projects:	(1)	(1)	(1)	(2)	(3)	(4)
1	Production	102,789		102,789	187,176	0	187,176
2	Transmission	469,870		469,870	679,730	0	679,730
3	Distribution	4,708,412	117,168	4,591,244	1,895,459	81,910	1,813,549
4	General & Intangible	1,800,919		1,800,919	807,580	0	807,580
5							0
6	Total Short Term CWIP	7,081,989	117,168	6,964,821	3,569,945	81,910	3,488,034
7							
8							
9	Long Term Projects					(3)	
10	Production	8,116,845		8,116,845	18,278,877		18,278,877
11	Transmission	973,307		973,307	6,512,077		6,512,077
12	Distribution	1,323,875		1,323,875	4,083,407		4,083,407
13	General & Intangible	1,006,426		1,006,426	1,328,054		1,328,054
14							0
15	Total Long Term CWIP	11,420,453	0	11,420,453	30,202,415	0	30,202,415
16							
17							
18	Total CWIP (Short + Long)	18,502,442	117,168	18,385,274	33,772,360	81,910	33,690,449
19	Not Chargeable	0					
20	Total CWIP Per Books	18,502,442	(5)		33,772,360	(6)	

- (1) A-2, Page 1 of 5 (2006 Actual)
 (2) A-2, Page 2 of 7
 (3) A-2, Page 3 of 7
 (4) Actual Balance Less Reimbursable
 (5) Ties to 12/31/06 F/S
 (6) Ties to 12/31/07 F/S

Otter Tail Power Company CWIP Actual 12 Months Ending 12/31/07

Prepared by: kas Reviewed by: pjb

Line No.		(A) Production	(B) Transmission	(C) Billable plus Distribution	(D) General & Intangible	(E) Total
	Short Term:					
	Total CWIP Balances by Function at Year Ending					
1	2007 (2)	\$17,052,204.36	\$7,003,988.48	\$ 5,822,498.14	\$2,021,269.29	\$31,899,960.27
2	AFUDC (2)	\$1,413,848.18	\$187,818.73	\$156,367.55	\$114,364.77	\$1,872,399.23
3	Total CWIP	\$18,466,052.54	\$7,191,807.21	\$5,978,865.69	\$2,135,634.06	\$33,772,359.50
4	Less Long Term (Below):	\$18,278,876.79	\$6,512,077.05	\$4,083,406.77	\$1,328,054.21	\$30,202,414.82
5	Short Term	\$187,175.75	\$679,730.16	\$1,895,458.92	\$807,579.85	\$3,569,944.68
6						
7	Long Term:	(A)	(B)	(C)	(D)	(E)
	Long Term CWIP Balances by Function at Year Ending					
8	2007 (1)	\$16,865,028.61	\$6,324,258.32	\$3,927,039.22	\$1,213,689.44	\$28,330,015.59
9	AFUDC	\$1,413,848.18	\$187,818.73	\$156,367.55	\$114,364.77	\$1,872,399.23
10	Long Term	\$18,278,876.79	\$6,512,077.05	\$4,083,406.77	\$1,328,054.21	\$30,202,414.82
11						
12	Total	\$18,466,052.54	\$7,191,807.21	\$5,978,865.69	\$2,135,634.06	\$33,772,359.50

(1) A-2 page 5 of 7
(2) A-2 page 3 of 7

Yr ending 07 CWIP by Function

A-2

Page 3 of 7

prepared by: kas
reviewed by:

	(A)	(B)	(C)	(D)
Line No.	CWIP Balances by Function at Year Ending 2007			AFUDC CWIP by function
1	Activity .0150. Billable			
2	Activity .0290. Distribution	\$ 5,822,498.14	156,367.55	5,978,865.69
3	Activity .0360. Plant	17,052,204.36	1,413,848.18	18,466,052.54
4	Activity .1140. General & Intangible	1,854,255.73	14,620.49	1,868,876.22
5	Activity .1145. General & Intangible	167,013.56	99,744.28	266,757.84
6	Activity .1510. Transmission	7,003,988.48	187,818.73	7,191,807.21
7	Interest - .0290. AFDC in Distribution	156,367.55		
8	Interest - .0360. AFDC in Plant	1,413,848.18		
9	Interest - .1140. AFDC in Gen & Intang	14,620.49		
10	Interest - .1145. AFDC in Gen & Intang	99,744.28		
11	Interest - .1510. AFDC in Transmission	187,818.73		
12	Total CWIP Balance at Year-Ending 2007	\$ 33,772,359.50	1,872,399.23	33,772,359.50
13				
14				
15				
16				
17	Billable Amonts in CWIP by Function at Year Ending 2007			
18	Activity .0150. Billable			
19	Activity .0290. Distribution	\$ 81,910.30		
20	Activity .0360. Plant	0.00		
21	Activity .1140. General & Intangible	0.00		
22	Activity .1145. General & Intangible	0.00		
23	Activity .1510. Transmission	0.00		
24	Total Billable Amounts in CWIP Balance at Year-Ending 2007	\$ 81,910.30	(A)	

Source: "CWIP AFUDC Billing Work" Spreadsheet Found in Supporting Workpaper File

(A) A-2; Page 1 - Current Year "Remove Reimbursable CWIP" Column.

Information requested for the Annual Cost of Services Studies on 1-15-2008

prepared by: kas
reviewed by:

Fixed Assets -- # 3 (with additional information attached in a separate worksheet)

Work Orders below are to be listed as Long Term Asset Work Orders:

(...source: COS Study work sheet by Bill Seelhammer.)

Line No.	(A) Function	(B) Work Order Number	(C) ADFC Amt at Year Ending 06	(D) Functional Acct Balances at Year-ending 2007				(G) Gen & Intang	(H) Functional Totals without ADFC	(I) Functional Totals with ADFC
				Transmission	Distribution	Plant				
1	1510	51786	51,967.99	1,959.53	(53,927.46)	0.00	0.00	0.00	(51,967.93)	0.06
2	1510	62417	441.04	775.44	0.00	0.00	0.00	0.00	775.44	1,216.48
3	290	62419	65.55	0.00	913.76	0.00	0.00	0.00	913.76	979.31
4	1510	62487	20.09	1,741.21	0.00	0.00	0.00	0.00	1,741.21	1,761.30
5	1510	62531	31.74	2,667.66	0.00	0.00	0.00	0.00	2,667.66	2,699.40
6	290	62564	(156.77)	0.00	0.00	0.00	0.00	0.00	0.00	(156.77)
7	290	63196	245.09	0.00	14,781.44	0.00	0.00	0.00	14,781.44	15,026.53
8	290	63966	142.42	0.00	6,730.06	0.00	0.00	0.00	6,730.06	6,872.48
9	1510	74141	967.71	18,632.99	0.00	0.00	0.00	0.00	18,632.99	19,600.70
10	290	74180	47.68	0.00	9,726.56	0.00	0.00	0.00	9,726.56	9,774.24
11	1510	74198	36,001.27	1,152,550.28	(1,038.89)	0.00	0.00	0.00	1,151,511.39	1,187,512.66
12	290	74200	506.20	0.00	25,228.23	0.00	0.00	0.00	25,228.23	25,734.43
13	1510	74201	343.68	24,269.55	0.00	0.00	0.00	0.00	24,269.55	24,613.23
14	1510	74219	509.57	10,560.07	0.00	0.00	0.00	0.00	10,560.07	11,069.64
15	290	74261	704.40	0.00	25,727.12	0.00	0.00	0.00	25,727.12	26,431.52
16	1510	74303	326.17	77,729.01	0.00	0.00	0.00	0.00	77,729.01	78,055.18
17	290	74382	220.64	0.00	(2,727.16)	0.00	0.00	0.00	(2,727.16)	(2,506.52)
18	290	74406	1,223.41	0.00	47,896.02	0.00	0.00	0.00	47,896.02	49,119.43
19	290	74455	1,437.40	0.00	59,061.98	0.00	0.00	0.00	59,061.98	60,499.38
20	290	74493	595.67	0.00	(432.49)	0.00	0.00	0.00	(432.49)	163.18
21	290	74502	1,680.14	0.00	68,436.74	0.00	0.00	0.00	68,436.74	70,116.88
22	290	74509	7,259.82	0.00	(7,052.06)	0.00	0.00	0.00	(7,052.06)	207.76
23	290	74523	423.26	0.00	24,857.06	0.00	0.00	0.00	24,857.06	25,280.32
24	290	74552	954.45	0.00	63,789.44	0.00	0.00	0.00	63,789.44	64,743.89
25	290	74584	470.38	0.00	12,994.18	0.00	0.00	0.00	12,994.18	13,464.56
26	290	74590	317.08	0.00	16,089.92	0.00	0.00	0.00	16,089.92	16,407.00
27	290	74713	1,149.37	0.00	40,452.87	0.00	0.00	0.00	40,452.87	41,602.24
28	290	74715	429.59	0.00	13,661.03	0.00	0.00	0.00	13,661.03	14,090.62
29	290	74720	455.07	0.00	14,109.89	0.00	0.00	0.00	14,109.89	14,564.96
30	1510	74750	11.07	401.26	0.00	0.00	0.00	0.00	401.26	412.33
31	290	74757	131.77	0.00	12,223.67	0.00	0.00	0.00	12,223.67	12,355.44
32	290	74760	646.74	0.00	42,248.04	0.00	0.00	0.00	42,248.04	42,894.78
33	290	74763	1,014.40	0.00	59,444.95	0.00	0.00	0.00	59,444.95	60,459.35
34	290	74764	1,049.83	0.00	61,166.08	0.00	0.00	0.00	61,166.08	62,215.91
35	290	74802	1,009.23	0.00	42,606.47	0.00	0.00	0.00	42,606.47	43,615.70
36	290	74837	641.61	0.00	67,458.83	0.00	0.00	0.00	67,458.83	68,100.44
37	290	74843	719.13	0.00	32,156.82	0.00	0.00	0.00	32,156.82	32,875.95
38	290	74850	86.20	0.00	12,407.02	0.00	0.00	0.00	12,407.02	12,493.22
39	290	74873	1,164.30	0.00	66,222.73	0.00	0.00	0.00	66,222.73	67,387.03
40	290	74888	70.26	0.00	0.00	0.00	0.00	0.00	0.00	70.26
41	290	74895	181.70	0.00	21,805.51	0.00	0.00	0.00	21,805.51	21,987.21
42	290	74896	876.73	0.00	56,370.92	0.00	0.00	0.00	56,370.92	57,247.65
43	290	74899	1,602.88	0.00	9,385.10	0.00	0.00	0.00	9,385.10	10,987.98
44	290	74901	81.17	0.00	0.00	0.00	0.00	0.00	0.00	81.17
45	290	74910	86.64	0.00	62.18	0.00	0.00	0.00	62.18	148.82
46	290	74926	435.99	0.00	34,505.68	0.00	0.00	0.00	34,505.68	34,941.67
47	290	74977	487.44	0.00	(362.45)	0.00	0.00	0.00	(362.45)	124.99
48	290	75008	433.25	0.00	(433.25)	0.00	0.00	0.00	(433.25)	0.00
49	290	75009	234.56	0.00	19,624.67	0.00	0.00	0.00	19,624.67	19,859.23
50	290	75010	335.82	0.00	34,283.53	0.00	0.00	0.00	34,283.53	34,619.35
51	290	75016	406.21	0.00	67,688.60	0.00	0.00	0.00	67,688.60	68,094.81
52	290	75017	1,489.21	0.00	(1,514.58)	0.00	0.00	0.00	(1,514.58)	(25.37)
53	290	75021	84.79	0.00	0.00	0.00	0.00	0.00	0.00	84.79
54	290	75023	415.59	0.00	19,600.60	0.00	0.00	0.00	19,600.60	20,016.19
55	290	75031	950.60	0.00	61,258.93	0.00	0.00	0.00	61,258.93	62,209.53
56	290	75050	233.94	0.00	28,079.60	0.00	0.00	0.00	28,079.60	28,313.54
57	290	75096	1,033.49	0.00	66,149.36	0.00	0.00	0.00	66,149.36	67,182.85
58	290	75097	170.00	0.00	7,814.66	0.00	0.00	0.00	7,814.66	7,984.66
59	290	75123	181.61	0.00	14,605.63	0.00	0.00	0.00	14,605.63	14,787.24
60	290	75137	77.60	0.00	27,964.05	0.00	0.00	0.00	27,964.05	28,041.65
61	290	75155	75.81	0.00	0.00	0.00	0.00	0.00	0.00	75.81
62	290	75158	109.03	0.00	12,070.32	0.00	0.00	0.00	12,070.32	12,179.35
63	290	75169	945.05	0.00	65,593.16	0.00	0.00	0.00	65,593.16	66,538.21
64	290	75170	179.60	0.00	19,768.24	0.00	0.00	0.00	19,768.24	19,947.84
65	290	75187	142.83	0.00	23,791.42	0.00	0.00	0.00	23,791.42	23,934.25
66	290	75216	100.11	0.00	22,237.08	0.00	0.00	0.00	22,237.08	22,337.19
67	290	75217	143.92	0.00	25,093.68	0.00	0.00	0.00	25,093.68	25,237.60
68	290	75220	148.66	0.00	12,760.32	0.00	0.00	0.00	12,760.32	12,908.98
69	290	75233	70.53	0.00	0.00	0.00	0.00	0.00	0.00	70.53

Line No.	(A) Function	(B) Work Order Number	(C) ADFC Amt at Year Ending 06	(D) Functional Acct Balances at Year-ending 2007				(G) Gen & Intang	(H) Functional Totals without ADFC	(I) Functional Totals with ADFC
				Transmission	Distribution	Plant				
70	290	75235	55.80	0.00	(55.80)	0.00		0.00	(55.80)	0.00
71	290	75246	698.37	0.00	48,370.22	0.00		0.00	48,370.22	49,068.59
72	290	75257	51.95	0.00	0.00	0.00		0.00	0.00	51.95
73	290	75269	106.43	0.00	9,091.21	0.00		0.00	9,091.21	9,197.64
74	290	75275	542.91	0.00	(242.94)	0.00		0.00	(242.94)	299.97
75	1510	75283	100.34	7,340.99	0.00	0.00		0.00	7,340.99	7,441.33
76	290	75295	267.86	0.00	45,777.80	0.00		0.00	45,777.80	46,045.66
77	290	75296	1,593.81	0.00	121,153.46	0.00		0.00	121,153.46	122,747.27
78	1510	75297	634.40	55,886.43	0.00	0.00		0.00	55,886.43	56,520.83
79	290	75311	178.78	0.00	16,833.63	0.00		0.00	16,833.63	17,012.41
80	290	75319	1,201.72	0.00	99,002.02	0.00		0.00	99,002.02	100,203.74
81	290	75322	190.90	0.00	16,470.26	0.00		0.00	16,470.26	16,661.16
82	290	75324	72.38	0.00	15,374.31	0.00		0.00	15,374.31	15,446.69
83	290	75325	66.42	0.00	15,006.88	0.00		0.00	15,006.88	15,073.30
84	290	75336	194.12	0.00	11,391.82	0.00		0.00	11,391.82	11,585.94
85	290	75339	36.59	0.00	0.00	0.00		0.00	0.00	36.59
86	290	75345	68.34	0.00	15,116.94	0.00		0.00	15,116.94	15,185.28
87	290	75357	90.84	0.00	11,791.50	0.00		0.00	11,791.50	11,882.34
88	290	75361	72.09	0.00	12,205.02	0.00		0.00	12,205.02	12,277.11
89	290	75374	67.53	0.00	19,764.94	0.00		0.00	19,764.94	19,832.47
90	290	75377	84.42	0.00	20,810.37	0.00		0.00	20,810.37	20,894.79
91	290	75378	133.24	0.00	16,257.55	0.00		0.00	16,257.55	16,390.79
92	290	75385	111.27	0.00	15,765.19	0.00		0.00	15,765.19	15,876.46
93	290	75386	106.54	0.00	12,495.54	0.00		0.00	12,495.54	12,602.08
94	290	75390	140.76	0.00	23,867.54	0.00		0.00	23,867.54	24,008.30
95	290	75410	399.20	0.00	32,021.27	0.00		0.00	32,021.27	32,420.47
96	290	75422	72.68	0.00	18,786.45	0.00		0.00	18,786.45	18,859.13
97	290	75432	155.57	0.00	34,199.96	0.00		0.00	34,199.96	34,355.53
98	290	75433	541.34	0.00	42,801.60	0.00		0.00	42,801.60	43,342.94
99	290	75438	441.94	0.00	40,199.63	0.00		0.00	40,199.63	40,641.57
100	290	75441	76.04	0.00	10,431.80	0.00		0.00	10,431.80	10,507.84
101	290	75446	478.28	0.00	54,769.44	0.00		0.00	54,769.44	55,247.72
102	290	75453	196.36	0.00	17,164.31	0.00		0.00	17,164.31	17,360.67
103	290	75457	101.34	0.00	15,625.38	0.00		0.00	15,625.38	15,726.72
104	290	75458	37.36	0.00	2,906.83	0.00		0.00	2,906.83	2,944.19
105	290	75460	59.27	0.00	34,652.55	0.00		0.00	34,652.55	34,711.82
106	290	75462	177.31	0.00	14,480.54	0.00		0.00	14,480.54	14,657.85
107	290	75470	94.11	0.00	13,531.10	0.00		0.00	13,531.10	13,625.21
108	290	75471	171.51	0.00	44,039.14	0.00		0.00	44,039.14	44,210.65
109	290	75480	20.79	0.00	10,372.37	0.00		0.00	10,372.37	10,393.16
110	290	75485	429.03	0.00	73,210.37	0.00		0.00	73,210.37	73,639.40
111	290	75492	160.04	0.00	22,797.04	0.00		0.00	22,797.04	22,957.08
112	290	75495	59.01	0.00	24,004.86	0.00		0.00	24,004.86	24,063.87
113	290	75499	150.88	0.00	37,933.46	0.00		0.00	37,933.46	38,084.34
114	290	75500	116.24	0.00	14,837.77	0.00		0.00	14,837.77	14,954.01
115	290	75501	61.34	0.00	5,689.44	0.00		0.00	5,689.44	5,750.78
116	290	75508	29.38	0.00	14,720.76	0.00		0.00	14,720.76	14,750.14
117	290	75518	68.87	0.00	11,136.69	0.00		0.00	11,136.69	11,205.56
118	290	75522	107.87	0.00	16,122.96	0.00		0.00	16,122.96	16,230.83
119	290	75523	9.64	0.00	3,742.68	0.00		0.00	3,742.68	3,752.32
120	290	75527	775.74	0.00	77,032.91	0.00		0.00	77,032.91	77,808.65
121	290	75528	280.11	0.00	23,716.89	0.00		0.00	23,716.89	23,997.00
122	290	75541	60.22	0.00	8,941.34	0.00		0.00	8,941.34	9,001.56
123	290	75552	37.16	0.00	9,390.69	0.00		0.00	9,390.69	9,427.85
124	290	75553	81.92	0.00	11,007.74	0.00		0.00	11,007.74	11,089.66
125	290	75557	58.44	0.00	14,761.35	0.00		0.00	14,761.35	14,819.79
126	290	75561	87.13	0.00	14,870.93	0.00		0.00	14,870.93	14,958.06
127	1510	75566	507.51	70,980.90	0.00	0.00		0.00	70,980.90	71,488.41
128	290	75569	803.33	0.00	82,070.95	0.00		0.00	82,070.95	82,874.28
129	290	75576	26.80	0.00	11,025.51	0.00		0.00	11,025.51	11,052.31
130	290	75581	93.93	0.00	18,123.68	0.00		0.00	18,123.68	18,217.61
131	1510	75589	764.26	113,744.90	0.00	0.00		0.00	113,744.90	114,509.16
132	290	75602	24.36	0.00	4,946.62	0.00		0.00	4,946.62	4,970.98
133	290	75603	133.76	0.00	17,946.85	0.00		0.00	17,946.85	18,080.61
134	290	75626	381.86	0.00	55,644.89	0.00		0.00	55,644.89	56,026.75
135	290	75637	28.67	0.00	11,133.16	0.00		0.00	11,133.16	11,161.83
136	290	75642	35.38	0.00	13,739.59	0.00		0.00	13,739.59	13,774.97
137	290	75649	43.79	0.00	21,384.33	0.00		0.00	21,384.33	21,428.12
138	290	75660	228.68	0.00	29,289.74	0.00		0.00	29,289.74	29,518.42
139	290	75678	51.95	0.00	12,786.59	0.00		0.00	12,786.59	12,838.54
140	290	75682	88.98	0.00	11,384.14	0.00		0.00	11,384.14	11,473.12
141	290	75697	64.93	0.00	15,706.00	0.00		0.00	15,706.00	15,770.93
142	290	75712	168.00	0.00	(6,329.45)	0.00		0.00	(6,329.45)	(6,161.45)
143	290	75729	95.48	0.00	18,620.05	0.00		0.00	18,620.05	18,715.53
144	290	75731	21.05	0.00	8,681.31	0.00		0.00	8,681.31	8,702.36
145	290	75758	115.57	0.00	28,226.16	0.00		0.00	28,226.16	28,341.73
146	290	75783	13.88	0.00	5,296.62	0.00		0.00	5,296.62	5,310.50
147	290	75787	5.27	0.00	2,011.90	0.00		0.00	2,011.90	2,017.17
148	1510	75790	316.41	120,727.41	0.00	0.00		0.00	120,727.41	121,043.82

Line No.	(A) Function	(B) Work Order Number	(C) ADFC Amt at Year Ending 06	(D) Functional Acct Balances at Year-ending 2007				(G) Gen & Intang	(H) Functional Totals without ADFC	(I) Functional Totals with ADFC
				Transmission	Distribution	Plant				
149	290	75805	168.74	0.00	64,382.50	0.00	0.00	0.00	64,382.50	64,551.24
150	290	75860	2.66	0.00	1,014.29	0.00	0.00	0.00	1,014.29	1,016.95
151	290	75867	29.46	0.00	11,241.38	0.00	0.00	0.00	11,241.38	11,270.84
152	290	102499	83,828.41	0.00	(83,553.51)	0.00	0.00	0.00	(83,553.51)	274.90
153	1140	102879	96,313.91	0.00	0.00	0.00	3,202.53	3,202.53	99,516.44	
154	1510	102903	5,805.26	3,825.62	(223.11)	0.00	0.00	0.00	3,602.51	9,407.77
155	360	102941	9,238.51	0.00	0.00	13,877.82	0.00	0.00	13,877.82	23,116.33
156	360	102954	22,983.55	0.00	0.00	105,293.30	0.00	0.00	105,293.30	128,276.85
157	1510	103082	1,268.13	14,969.05	0.00	0.00	0.00	0.00	14,969.05	16,237.18
158	1510	103100	62,586.49	150,450.24	0.00	(68,505.49)	0.00	0.00	81,944.75	144,531.24
159	360	103101	764,935.08	1,979,249.00	0.00	5,153,907.49	0.00	0.00	7,133,156.49	7,898,091.57
160	360	103165	4,921.02	0.00	0.00	50,980.03	0.00	0.00	50,980.03	55,901.05
161	360	103228	35,133.43	0.00	0.00	920,066.55	0.00	0.00	920,066.55	955,199.98
162	1510	103292	842.54	6,918.36	0.00	0.00	0.00	0.00	6,918.36	7,760.90
163	360	103296	5,291.24	0.00	0.00	44,529.72	0.00	0.00	44,529.72	49,820.96
164	1510	103317	45,793.19	591,439.45	34,749.94	0.00	0.00	0.00	626,189.39	671,982.58
165	360	103325	116.87	0.00	0.00	196,143.95	0.00	0.00	196,143.95	196,260.82
166	1510	103369	4,597.34	102,600.00	0.00	0.00	0.00	0.00	102,600.00	107,197.34
167	360	103370	2,735.43	0.00	0.00	135,528.92	0.00	0.00	135,528.92	138,264.35
168	360	103371	49,530.35	0.00	0.00	1,021,820.38	0.00	0.00	1,021,820.38	1,071,350.73
169	1510	103376	7,313.64	178,366.78	7,075.66	0.00	0.00	0.00	185,442.44	192,756.08
170	360	103399	2,179.44	0.00	0.00	(2,179.44)	0.00	0.00	(2,179.44)	0.00
171	360	103401	51,092.66	0.00	0.00	(51,092.66)	0.00	0.00	(51,092.66)	0.00
172	360	103402	198,901.76	0.00	0.00	(198,901.76)	0.00	0.00	(198,901.76)	0.00
173	360	103404	52,824.55	0.00	0.00	(52,824.55)	0.00	0.00	(52,824.55)	0.00
174	360	103405	11,332.34	0.00	0.00	(11,332.34)	0.00	0.00	(11,332.34)	0.00
175	290	103476	15,459.40	0.00	552,668.53	0.00	0.00	0.00	552,668.53	568,127.93
176	1510	103487	8,584.01	306,840.15	0.00	0.00	0.00	0.00	306,840.15	315,424.16
177	1510	103488	4,468.23	208,375.15	0.00	0.00	0.00	0.00	208,375.15	212,843.38
178	1510	103489	4,378.52	161,343.78	0.00	0.00	0.00	0.00	161,343.78	165,722.30
179	360	103490	287.15	0.00	0.00	25,521.72	0.00	0.00	25,521.72	25,808.87
180	290	103491	6,103.68	0.00	238,191.82	0.00	0.00	0.00	238,191.82	244,295.50
181	360	103492	1,336.87	0.00	0.00	(1,336.87)	0.00	0.00	(1,336.87)	0.00
182	360	103494	(377.68)	0.00	0.00	377.68	0.00	0.00	377.68	0.00
183	1140	103495	10,831.67	0.00	0.00	0.00	639,065.13	639,065.13	649,896.80	
184	360	103496	377.68	0.00	0.00	(377.68)	0.00	0.00	(377.68)	0.00
185	360	103501	60.98	0.00	0.00	7,801.81	0.00	0.00	7,801.81	7,862.79
186	360	103505	699.79	0.00	0.00	65,902.78	0.00	0.00	65,902.78	66,602.57
187	360	103506	72.17	0.00	0.00	28,028.00	0.00	0.00	28,028.00	28,100.17
188	360	103507	111.74	0.00	0.00	11,701.74	0.00	0.00	11,701.74	11,813.48
189	360	103509	80.12	0.00	0.00	(38.74)	0.00	0.00	(38.74)	41.38
190	360	103511	954.36	0.00	0.00	79,515.15	0.00	0.00	79,515.15	80,469.51
191	360	103515	1,546.43	0.00	0.00	341,295.01	0.00	0.00	341,295.01	342,841.44
192	360	103516	281.52	0.00	0.00	17,265.86	0.00	0.00	17,265.86	17,547.38
193	360	103517	36.97	0.00	0.00	(36.97)	0.00	0.00	(36.97)	0.00
194	360	103518	1,827.23	0.00	0.00	92,524.49	0.00	0.00	92,524.49	94,351.72
195	360	103521	394.29	0.00	0.00	68,023.73	0.00	0.00	68,023.73	68,418.02
196	360	103524	114.34	0.00	0.00	21,875.00	0.00	0.00	21,875.00	21,989.34
197	360	103525	57.95	0.00	0.00	22,112.83	0.00	0.00	22,112.83	22,170.78
198	360	103526	134.04	0.00	0.00	11,793.62	0.00	0.00	11,793.62	11,927.66
199	360	103527	4,239.88	0.00	0.00	192,937.50	0.00	0.00	192,937.50	197,177.38
200	360	103532	(9.18)	0.00	0.00	9.18	0.00	0.00	9.18	0.00
201	360	103536	19,150.24	0.00	0.00	1,007,950.35	0.00	0.00	1,007,950.35	1,027,100.59
202	360	103540	93,593.41	0.00	0.00	6,124,316.42	0.00	0.00	6,124,316.42	6,217,909.83
203	360	103545	9.18	0.00	0.00	(9.18)	0.00	0.00	(9.18)	0.00
204	1510	103546	6.15	786.83	0.00	0.00	0.00	0.00	786.83	792.98
205	1510	103550	7.19	869.70	0.00	0.00	0.00	0.00	869.70	876.89
206	1510	103551	201.35	8,705.22	0.00	0.00	0.00	0.00	8,705.22	8,906.57
207	1510	103552	84.47	7,573.81	0.00	0.00	0.00	0.00	7,573.81	7,658.28
208	360	103554	1,013.74	0.00	0.00	83,748.61	0.00	0.00	83,748.61	84,762.35
209	360	103560	6,561.15	0.00	0.00	762,197.79	0.00	0.00	762,197.79	768,758.94
210	360	103562	57.07	0.00	0.00	1,754.94	0.00	0.00	1,754.94	1,812.01
211	1140	103564	1,109.15	0.00	0.00	0.00	136,624.56	136,624.56	137,733.71	
212	360	103565	3,710.24	0.00	0.00	512,762.99	0.00	0.00	512,762.99	516,473.23
213	360	103570	112.15	0.00	0.00	7,855.67	0.00	0.00	7,855.67	7,967.82
214	360	103572	49.67	0.00	0.00	10,989.25	0.00	0.00	10,989.25	11,038.92
215	1145	103574	3,430.37	0.00	0.00	0.00	177,006.78	177,006.78	180,437.15	
216	1140	103577	84.02	0.00	0.00	0.00	14,798.24	14,798.24	14,882.26	
217	1140	103578	702.89	0.00	0.00	0.00	20,904.97	20,904.97	21,607.86	
218	1140	103581	291.90	0.00	0.00	0.00	71,615.84	71,615.84	71,907.74	
219	1510	103588	58.38	17,425.65	0.00	0.00	0.00	0.00	17,425.65	17,484.03
220	1510	103589	3,176.71	157,777.35	0.00	0.00	0.00	0.00	157,777.35	160,954.06
221	290	103595	201.26	0.00	239.56	0.00	0.00	0.00	239.56	440.82
222	1510	103600	67.68	1,864.28	0.00	0.00	0.00	0.00	1,864.28	1,931.96
223	360	103604	3,279.15	0.00	0.00	93,247.03	0.00	0.00	93,247.03	96,526.18
224	1510	103610	2,017.27	96,805.08	0.00	0.00	0.00	0.00	96,805.08	98,822.35
225	1510	103615	4,789.62	397,569.71	0.00	0.00	0.00	0.00	397,569.71	402,359.33
226	1140	103617	1,225.54	0.00	0.00	0.00	63,301.98	63,301.98	64,527.52	
227	1510	103625	1,085.09	146,792.70	0.00	0.00	0.00	0.00	146,792.70	147,877.79

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line No.	Function	Work Order Number	ADFC Amt at Year Ending 06	Functional Acct Balances at Year-ending 2007				Functional Totals without AFDC	Functional Totals with AFDC
				Transmission	Distribution	Plant	Gen & Intang		
228	360	103628	282.81	0.00	0.00	18,006.98	0.00	18,006.98	18,289.79
229	1510	103642	3.63	282.66	0.00	0.00	0.00	282.66	286.29
230	1140	103643	237.30	0.00	0.00	0.00	33,048.73	33,048.73	33,286.03
231	1140	103644	57.87	0.00	0.00	0.00	22,080.65	22,080.65	22,138.52
232	1140	103645	41.68	0.00	0.00	0.00	16,185.47	16,185.47	16,227.15
233	1140	103646	38.47	0.00	0.00	0.00	15,854.56	15,854.56	15,893.03
234	1510	103649	276.15	104,028.03	0.00	0.00	0.00	104,028.03	104,304.18
235	1510	103656	41.83	15,960.09	0.00	0.00	0.00	15,960.09	16,001.92
236	1510	103777	9.10	3,472.00	0.00	0.00	0.00	3,472.00	3,481.10
237		Totals	1,872,399.23	6,324,258.32	3,927,039.22	16,865,028.61	1,213,689.44	28,330,015.59	30,202,414.82
238				(1)	(2)	(3)	(4)		
239									
240	Function	Work Order Number	ADFC Amt at Year Ending 06	Transmission	Distribution	Plant	Gen & Intang	Functional Totals without AFDC	Functional Totals with AFDC
241									
242									
243									
244								CWIP at 12-31-6	33,772,359.50
245								less: above long-term work orders	(30,202,414.82)
246								Remaining balance equal to short-term work order balance	3,569,944.68

- (1) A-2; Page 2, Column (B).
(2) A-2; Page 2, Column (C).
(3) A-2; Page 2, Column (A).
(4) A-2; Page 2, Column (D).

Source: "CWIP AFUDC Billing Work" Spreadsheet Found in Supporting Workpaper File

Prepared by: kas
Checked by: pjb

Otter Tail Power Company
Material & Supplies: Split to Transmission and Distribution
Actual Year Ending December 31, 2007

Line No.	(A)	(B)
1	Materials & Supplies - All Other	<u>\$9,725,539</u> (1)
2	Transmission @ 37.00% (2)	3,598,449
3	Distribution @ 63.00% (2)	<u>6,127,090</u>
4	Total	<u>\$9,725,539</u>
(1) A-3, Page 2 of 3 (2) A-3, Page 3 of 3		

Otter Tail Power Company
Material & Supplies
Actual Year Ending December 31, 2007

Prepared by: bcb
Checked by: pjb

	(A)	(B)	(C)	(D)	(E)	(F)
Line No.				(1)		
				Production	All Other	Total
1	December	End	2006	3,601,522	8,799,997	12,401,519
2	January	End	2007	3,612,871	8,932,142	12,545,013
3		Beg	2007	3,612,871	8,932,142	12,545,013
4	February	End	2007	3,669,102	9,270,894	12,939,996
5		Beg	2007	3,669,102	9,270,894	12,939,996
6	March	End	2007	3,720,469	9,921,982	13,642,451
7		Beg	2007	3,720,469	9,921,982	13,642,451
8	April	End	2007	3,778,513	10,182,289	13,960,802
9		Beg	2007	3,778,513	10,182,289	13,960,802
10	May	End	2007	3,833,627	9,851,105	13,684,732
11		Beg	2007	3,833,627	9,851,105	13,684,732
12	June	End	2007	3,806,086	10,086,832	13,892,918
13		Beg	2007	3,806,086	10,086,832	13,892,918
14	July	End	2007	3,802,234	9,910,948	13,713,182
15		Beg	2007	3,802,234	9,910,948	13,713,182
16	August	End	2007	3,851,282	10,057,599	13,908,881
17		Beg	2007	3,851,282	10,057,599	13,908,881
18	September	End	2007	3,827,607	9,759,096	13,586,703
19		Beg	2007	3,827,607	9,759,096	13,586,703
20	October	End	2007	3,838,302	9,631,609	13,469,911
21		Beg	2007	3,838,302	9,631,609	13,469,911
22	November	End	2007	3,807,222	9,742,049	13,549,271
23		Beg	2007	3,807,222	9,742,049	13,549,271
24	December	End	2007	3,855,188	9,919,848	13,775,036
25	Total			90,551,340	233,412,935	323,964,275
26	Average			3,772,973	9,725,539	13,498,511

(1) Includes Energy Delivery, Fleet Srv Center, & Central Stores.

Source: Appropriate Month Financial Statement, Page 9

Prepared by: kas
Checked by: pjb

Otter Tail Power Company
Distribution and Transmission Plant Supplies
Actual Year Ending December 31, 2007

Line No.	(A)	(B)	(C)
		<u>Amounts</u>	<u>%s</u>
1	Transmission Plant (1)	3,569,715	37.00%
2	Distribution Plant (2)	<u>6,078,164</u>	63.00%
3	Total	9,647,879	100.00%
(1) Ferc Form 1 , Page 227, Line 8 (2) Ferc Form 1 , Page 227, Line 9			

Otter Tail Power Company
Prepayments
Actual 12 Months Ending December 31, 2007

Prepared by: kas
Checked by: pjb

	(A)	(B)	(C)	(D)	(E)			
Line No.				Prepaid Insurance And Interest		Less A/C 165.12		Total a/c 165
				(1)		(2)		
1	December	End	2006	165,943		n/a		165,943
2	January	End	2007	83,835		n/a		83,835
3		Beg	2007	83,835		n/a		83,835
4	February	End	2007	986,357		n/a		986,357
5		Beg	2007	986,357		n/a		986,357
6	March	End	2007	801,894		n/a		801,894
7		Beg	2007	801,894		n/a		801,894
8	April	End	2007	682,150		n/a		682,150
9		Beg	2007	682,150		n/a		682,150
10	May	End	2007	1,147,490		n/a		1,147,490
11		Beg	2007	1,147,490		n/a		1,147,490
12	June	End	2007	1,039,382		n/a		1,039,382
13		Beg	2007	1,039,382		n/a		1,039,382
14	July	End	2007	879,562		n/a		879,562
15		Beg	2007	879,562		n/a		879,562
16	August	End	2007	726,768		n/a		726,768
17		Beg	2007	726,768		n/a		726,768
18	September	End	2007	611,704		n/a		611,704
19		Beg	2007	611,704		n/a		611,704
20	October	End	2007	458,910		n/a		458,910
21		Beg	2007	458,910		n/a		458,910
22	November	End	2007	305,815		n/a		305,815
23		Beg	2007	305,815		n/a		305,815
24	December	End	2007	152,359		n/a		152,359
25	Total			15,766,036		0		15,766,036
26	Average			656,918		0		656,918
27	Noncurrent Prepaid Pension Expense (3)							0
28	Post Retirement Benefits other than Pension (FAS 106) (4)							(32,877,510)
29	Post Employment Benefits other than Pension (FAS 112) (5)							(3,297,451)
30	Total Prepayments in Rate Base							(35,518,043)
	(1) Appropriate Month Financial Statement - Page 2							
	(2) Not applicable							
	(3) A-4, Page 2 of 4							
	(4) A-4, Page 3 of 4							
	(5) A-4, Page 4 of 4							

Prepared by: kas
Checked by: pjb

Otter Tail Power Company Noncurrent Prepaid Pension Expense Actual 12 Months Ending December 31, 2007

		(A)	(B)	(C)	(D)	(E)
Line No.	Acct # 128.2/1612.000					Monthly Balances
1	December	End	2006			0
2	January	End	2007			0
3		Beg	2007			0
4	February	End	2007			0
5		Beg	2007			0
6	March	End	2007			0
7		Beg	2007			0
8	April	End	2007			0
9		Beg	2007			0
10	May	End	2007			0
11		Beg	2007			0
12	June	End	2007			0
13		Beg	2007			0
14	July	End	2007			0
15		Beg	2007			0
16	August	End	2007			0
17		Beg	2007			0
18	September	End	2007			0
19		Beg	2007			0
20	October	End	2007			0
21		Beg	2007			0
22	November	End	2007			0
23		Beg	2007			0
24	December	End	2007			0
25	Total					0
26	Average	(Amount to A-4, page 1 of 2)				0

Source: Account 1612 per FERC data base (Excel w/s in Misc W/P File or GL Fire)

(F)	(G)	(H)	(I)	(J)
YEAR	MONTH	SumOfCurrent Month	SumOfBalance	ACCT
2006	12	(\$8,487,092.09)	\$0.00	1612
2007	1	\$0.00	\$0.00	1612
2007	2	\$0.00	\$0.00	1612
2007	3	\$0.00	\$0.00	1612
2007	4	\$0.00	\$0.00	1612
2007	5	\$0.00	\$0.00	1612
2007	6	\$0.00	\$0.00	1612
2007	7	\$0.00	\$0.00	1612
2007	8	\$0.00	\$0.00	1612
2007	9	\$0.00	\$0.00	1612
2007	10	\$0.00	\$0.00	1612
2007	11	\$0.00	\$0.00	1612
2007	12	\$0.00	\$0.00	1612

YEAR	MONTH	SumOfCurrent Month	SumOfBalance	ACCT
2006	12	(\$891,735.00)	\$0.00	1805
2007	1	\$0.00	\$0.00	1805
2007	2	\$0.00	\$0.00	1805
2007	3	\$0.00	\$0.00	1805
2007	4	\$0.00	\$0.00	1805
2007	5	\$0.00	\$0.00	1805
2007	6	\$0.00	\$0.00	1805
2007	7	\$0.00	\$0.00	1805
2007	8	\$0.00	\$0.00	1805
2007	9	\$0.00	\$0.00	1805
2007	10	\$0.00	\$0.00	1805
2007	11	\$0.00	\$0.00	1805
2007	12	\$0.00	\$0.00	1805

SRP intangible asset \$ -
Per Balance Sheet \$0.00
\$0.00

Prepared by: kas
Checked by: pljb

Offer Tail Power Company
Post Retirement Benefits Other Than Pension
Actual 12 Months Ending December 31, 2007

(A) (B) (C) (D) (E) (F) (G) (H) (I) (J) (K)

Line No.	Month	End	Provision	YEAR	MONTH	SumOfCurrent Month	SumOfBalance	ACCT	SUB
1	December	2006	(32,254,146)	2006	12	(\$4,178,444.71)	(\$35,804,531.15)	2440	3200
3	January	2007	(32,687,839)	2007	1	(\$401,693.68)	(\$36,206,224.83)	2440	3200
4	Beg	2007	(32,687,839)	2007	2	(\$20,477.52)	(\$36,226,702.35)	2440	3200
5	End	2007	(32,561,650)	2007	3	(\$167,552.76)	(\$36,394,255.11)	2440	3200
6	February	2007	(32,561,650)	2007	4	(\$255,025.34)	(\$36,649,280.45)	2440	3200
7	Beg	2007	(32,763,953)	2007	5	(\$206,498.10)	(\$36,855,778.55)	2440	3200
8	End	2007	(32,882,312)	2007	6	(\$174,051.27)	(\$37,029,829.82)	2440	3200
9	Beg	2007	(32,763,953)	2007	7	(\$192,313.11)	(\$37,222,142.93)	2440	3200
10	End	2007	(32,952,144)	2007	8	(\$292,080.32)	(\$37,514,223.25)	2440	3200
11	May	2007	(32,952,144)	2007	9	(\$65,415.35)	(\$37,579,638.60)	2440	3200
12	Beg	2007	(32,989,528)	2007	10	\$252,736.71	(\$37,326,901.89)	2440	3200
13	End	2007	(32,989,528)	2007	11	(\$168,726.01)	(\$37,495,627.90)	2440	3200
14	Beg	2007	(33,045,175)	2007	12	\$2,819,212.89	(\$34,676,415.01)	2440	3200
15	End	2007	(33,045,175)	2007					
16	August	2007	(33,277,313)	2007					
17	Beg	2007	(33,277,313)	2007					
18	End	2007	(33,335,013)	2007					
19	September	2007	(33,335,013)	2007					
20	Beg	2007	(33,254,489)	2007					
21	End	2007	(33,254,489)	2007					
22	October	2007	(33,409,755)	2007					
23	Beg	2007	(33,409,755)	2007					
24	End	2007	(30,487,764)	2007					
25	November	2007	(789,060,249)	2007					
26	Beg	2007	(32,877,510)	2007					
27	End	2007	(32,877,510)	2007					
28	Total								
29	Average								

YEAR	MONTH	SumOfCurrent Month	SumOfBalance	ACCT	SUB
2006	12	\$128,547.00	\$3,550,385.52	2440	3250
2007	1	(\$31,999.67)	\$3,518,385.85	2440	3250
2007	2	\$146,666.66	\$3,665,052.51	2440	3250
2007	3	(\$34,750.80)	\$3,630,301.71	2440	3250
2007	4	\$136,666.67	\$3,766,968.38	2440	3250
2007	5	\$136,666.66	\$3,903,635.04	2440	3250
2007	6	\$136,666.67	\$4,040,301.71	2440	3250
2007	7	\$136,666.67	\$4,176,968.38	2440	3250
2007	8	\$59,942.24	\$4,236,910.62	2440	3250
2007	9	\$7,715.23	\$4,244,625.85	2440	3250
2007	10	(\$172,212.50)	\$4,072,413.35	2440	3250
2007	11	\$13,459.21	\$4,085,872.56	2440	3250
2007	12	\$102,778.75	\$4,188,651.31	2440	3250

Source: GL Fire

Prepared by: kas
Checked by: pjb

Otter Tail Power Company
Post Employment Benefits
Actual 12 Months Ending December 31, 2007

Line No. (A) (B) (C) (D) (E) (F) (G) (H) (I) (J)

No.	Account 228.33/2440.3300				
	<u>Month</u>			<u>Provision</u>	
1	December	End	2006	(3,280,706)	
2	January	End	2007	(3,291,027)	
3		Beg	2007	(3,291,027)	
4	February	End	2007	(3,301,164)	
5		Beg	2007	(3,301,164)	
6	March	End	2007	(3,306,224)	
7		Beg	2007	(3,306,224)	
8	April	End	2007	(3,322,560)	
9		Beg	2007	(3,322,560)	
10	May	End	2007	(3,335,659)	
11		Beg	2007	(3,335,659)	
12	June	End	2007	(3,335,562)	
13		Beg	2007	(3,335,562)	
14	July	End	2007	(3,344,875)	
15		Beg	2007	(3,344,875)	
16	August	End	2007	(3,338,707)	
17		Beg	2007	(3,338,707)	
18	September	End	2007	(3,239,514)	
19		Beg	2007	(3,239,514)	
20	October	End	2007	(3,244,123)	
21		Beg	2007	(3,244,123)	
22	November	End	2007	(3,244,072)	
23		Beg	2007	(3,244,072)	
24	December	End	2007	(3,251,143)	
25	Total			(79,138,823)	
26					
27	Average			(3,297,451)	

(2) Per GL Fire Monthly Activity Total for Acct 2440-3300.
(3) Per GL Fire Monthly Totals for Acct 2440-3300

Otter Tail Power Company
Accumulated Deferred Income Tax
Actual Year 2007

Prepared by: kas
Reviewed by: pjb

	(A)	(B)	(C)	(D)	(E)
Line No.	Accumulated Deferred Income Taxes (B/S):	FEDERAL	MINNESOTA	NORTH DAKOTA	TOTAL
1	Accumulated Deferred Income Taxes @ 12/31/06				
2	Total Balance (1)	(62,817,827)	(8,814,090)	(4,554,133)	(76,186,049)
3	Adjustments to Beginning Balance for Items				
4	Beginning Balances Restated	(62,817,827)	(8,814,090)	(4,554,133)	(76,186,049)
5	Less: Items Sd Flows Through (1)	(4,155,391)	(637,248)	(365,017)	(5,157,656)
6	All Other ADIT	(58,662,435)	(8,176,842)	(4,189,116)	(71,028,393)
7	2007 Adjustments To 12/31/06 ADIT Balance:				
8	Total Accrual (2)	(2,494,145)	(279,529)	(188,781)	(2,962,455)
9	Total Allowed Prior Period Adjustments	(2,494,145)	(279,529)	(188,781)	(2,962,455)
10	Less: Items Sd Flows Through (6)	0	0	0	0
11	All Other ADIT	(2,494,145)	(279,529)	(188,781)	(2,962,455)
12	Adjusted Accum. Deferred Inc. Taxes @ 12/31/06				
13	Total Balance (3)	(65,311,972)	(9,093,619)	(4,742,914)	(79,148,504)
14	Less: Items Sd Flows Through	(4,155,391)	(637,248)	(365,017)	(5,157,656)
15	All Other ADIT	(61,156,580)	(8,456,371)	(4,377,897)	(73,990,848)
16	Actual Year 2007 Deferred Income Tax Accrual				
17	Total Accrual (6)	(339,047)	(100,685)	(51,699)	(491,431)
18	Less: Adj needed to set-up corporate balance (8)	(7)	(2)	(1)	(10)
19	FAS 87 adjustment offset to Retained earnings	(339,054)	(100,687)	(51,700)	(491,441)
20	Subtotal	(103,520)	(30,742)	(15,785)	(150,047)
21	Less: Items Sd Flows Through (6)	(587,347)	(68,662)	(53,223)	(709,232)
22	All Other ADIT	144,773	(62,767)	(14,262)	67,744
23	Accumulated Deferred Income Taxes @ 12/31/07				
24	Total Balance (4)	(65,754,546)	(9,225,047)	(4,810,399)	(79,789,992) (7)
25	Less: Items Sd Flows Through (4)	(4,742,738)	(705,910)	(418,240)	(5,866,888)
26	All Other ADIT	(61,011,807)	(8,519,137)	(4,392,159)	(73,923,104)
27	Accumulated Deferred Income Taxes				
28	Items Sd Flows Through				
29	Federal	(4,155,391)	(4,742,738)	(4,449,065)	
30	Minnesota	(637,248)	(705,910)	(391,629)	
31	North Dakota	(365,017)	(418,240)		
32	Subtotal	(5,157,656)	(5,866,888)	(5,512,272)	
33	All Other				
34	Federal	(61,156,580)	(61,011,807)	(61,084,194)	
35	Minnesota	(8,456,371)	(8,519,137)	(8,487,754)	
36	North Dakota	(4,377,897)	(4,392,159)	(4,385,028)	
37	Subtotal	(73,990,848)	(73,923,104)	(73,956,976)	
38	Total Accumulated Deferred Income Taxes	(79,148,504)	(79,789,992)	(79,469,248)	
39			(7)		
40	(1) 2006 Actual Year Coss, W/P A-5, Page 1 Of 5				
41	(2) A-5, Page 4 Of 5				
42	(3) 12/31/06 Balances Plus 2007 Adjustments To 12/31/06 Balance Per A-5, Page 2 Of 5				
43	(4) Adjusted 12/31/2006 Balance Plus 2007 Accrual				
44	(5) Average Of Adjusted 12/31/06 And 12/31/07 Balances				
45	(6) A-5, page 3 of 5				
46	(7) Agrees To Coss Balance, 12/31/07 Per A-5, Page 2 Of 5; difference of 1,490 carried from 2006.				
47	\$1,338 of difference relates to 1998.				
48	(8) See footnote (17) on A-5, Page 2 of 5.				(79,791,482)
49					
50					1,490

Otter Tail Power Company
ACCUMULATED DEFERRED INCOME TAX
Actual Year 2007

Prepared by: kas
Reviewed by: pjb

Line No.	(A)	(B)	(C)	(D)
	Balance Per Books	12/31/2006	CHANGE	12/31/2007
1	Account 1822.3000 (182.3) SFAS 109 Regulatory Asset	11,711,893 (1)	2,979,079	8,732,814 (2)
2	Account 1895.1000 (190) Accumulated Deferred Income Taxes - Utility	29,112,339 (1)	(2,521,619)	31,633,958 (2)
3	Account 1895.2000 (190.2) Accumulated Deferred Income Taxes - ITC	5,231,699 (1)	726,715	4,504,984 (2)
4	Account 1895.2100 (190.2) Accumulated Deferred Income Taxes - Wind	0	0	0 (2)
5	Account 1895.9300 (190.93) SFAS 109 ADIT Debits	(307,546) (1)	(46,216)	(261,330) (2)
6	Account 1895.9800 (190.98) Current Portion of ADIT Debits	1,227,452 (1)	(28,301)	1,255,753 (2)
7	Account 1895.9900 (190.99) Contra Current Portion of ADIT Debits	(1,227,452) (1)	28,301	(1,255,753) (2)
8	Account 2510.1000 (254) Regulatory Liability	(5,228,395) (1)	(726,715)	(4,501,680) (9)
9	Account 2575-2000 (282) - Utility operations	(103,635,502) (1)	6,183,035	(109,818,537) (2)
10	Account 2575-2010 (282) - ADIT - Wind	0	0	0 (2)
11	Account 2575.2100 (282.93) SFAS 109 ADIT credits - Property	(11,372,375) (1)	(2,945,721)	(8,426,654) (2)
12	Account 2575.3000 (283) ADIT Other utility operations	(1,648,416) (1)	(154,320)	(1,494,096) (2)
13	Account 2575.3210/3220 (283.10) ADIT Big Stone	(22,805) (1)	(6,679)	(16,126) (2)
14	Account 2575.3400 (283.93) SFAS 109 ADIT Credits - Nonproperty	(31,972) (1)	12,858	(44,830) (2)
15	Account 2575.3980 (283.98) Current Portion of ADIT Credits	(483,267) (1)	(45,319)	(437,948) (2)
16	Account 2575.3990 (283.99) Contra Current Portion of ADIT Credits	483,267 (1)	45,319	437,948 (2)
17	Total Utility Accumulated Deferred Income Taxes Per Books	(76,191,080)	3,500,417	(79,691,497) (3)
18	Less: Jurisdictional Deferred Tax Items			
19	Amortization Of Big Stone Deferred Taxes	(22,810) (1)	(6,679) (5)	(16,131)
20	Amortization Of Spiritwood Deferred Taxes	0 (1)	0 (5)	0
21	Minnesota Cip Tracker Account	(243,773) (1)	(104,751) (5)	(139,022)
22	Reserve For North Dakota Loan Pool	0 (1)	0 (5)	0
23	Cass County Donation	0 (1)	0 (5)	0
24	Non cost of service items	263,042 (1)	7,904 (5)	255,138
25	Total Jurisdictional Deferred Income Taxes	(3,541)	(103,526) (14)	99,985
26		(76,187,539)	3,603,943	(79,791,482)
27	Adjustments			
28	Portion of Account 190 on Corporate Books - detail of 190 acct Def 43	0	0	0
29			3,603,943	
30	Less: Prior Period Adjustments Included in Amounts Above			
31	Total PPA's Included in ADIT per Books Above		2,962,455	
32	Total Prior Periods Adj Eliminated		2,962,455	
33				
34	Current Year Systemwide Utility Deferred Tax Expense		641,488 (7)	
35				
36	Current Year Coss Utility Deferred Tax Balance	(76,187,539)		(79,791,482)
37				
38				
39				
40	(1) Agrees to 2006 Actual Year Coss, A-5, Page 2 Of 5 and agrees to 2006 balances on GL by running Oracle OTPGL700 Reports			
41				
42	(2) 12/31/07 General Ledger Balance less nonutility accounts from Year-End Tax Accrual, Def 36-38			
43	(3) 12/31/07 Financial Statement, Page 2 + 3, Deferred Income Taxes, Less Non-Utility A/C 190.1, 282.1 & 283.1			
44	(ADIT p. 2 + Regulatory Asset, Deferred Taxes p. 2 + Regulatory Liability, Deferred Taxes p.3 + ADIT p. 3)			
45				
46	Balance Per Books	(79,691,497)		
47	Accum Def Taxes - Nonutility & Other A/C 190.1	(97,417) (10)		
48	Accum Def Taxes - Nonutility & Other A/C 190.2	12,988,625 (15)		
49	Accum Def Taxes - Nonutility & Other A/C 282.0	(3,355,625) (15)		
50	Accum Def Taxes - Nonutility & Other A/C 282.1	(1,456,944) (11)		
51	Accum Def Taxes - Nonutility & Other A/C 283.0	3 (16)		
52	Accum Def Taxes - Nonutility & Other A/C 283.1	(353,584) (12)		
53	SFAS 109 Regulatory Liability - ADIT Debits A/C 254-1 (9)	0		
54		7,725,058	(71,966,439)	(71,966,439) check total
55				(0) difference
56	(4) N/A			
57	(5) A-5, Page 4 Of 5			
58	(6) Not Used			
59	(7) Current Year Systemwide Utility Deferred Tax Expense		641,488	
60	Adjustments To Expense:			
61	Gain On Bonds - South Dakota Flowthrough			
62	FAS 87		150,047 (12)	
63	Acct 283		10 (17)	
64	Current Year Systemwide Entries to Deferred Tax Expense		491,431 (5)	
65				0 Rounding
66	(8) N/A			
67	(9) Adjusted \$3,840 for non-utility ITC 1976 Vintage in balance when account was set up			
68	Amt from 1993 Tax Accrual Def5	11,666		
69	2007 Effective Tax Rate	39.00%		
70		4,550		
71	Non-utility items that appear to have been removed from 12/31/07 balances:			

Line No.	(A)	(B)	(C)	(D)
1	(10) Year End Tax Accrual W/P Def 43 page 6 of 6, a/c 190.1			
2	(11) Year End Tax Accrual W/P Def 44 page 4 of 4, a/c 282.1			
3	(12) Year End Tax Accrual W/P Def 45 page 1 & 2 of 3, a/c 283 & 283.1, adjustment does not include FAS 87 entry made			
4	\$(150,047) per FAS 109 requirements directly to Retained Earnings. Adj is only 283.1 \$(1,347,627) and \$9,664 + \$984,379 on			
5	'Corp books (per Income Tax Accountant, Tax accg.)			
6	(13) N/A			
7	(14) Jurisdictional Deferred Tax Adjustments		(103,526)	
8	Prior Period Adjustments			
9	MN PUC Refund Reversal		0	
10	Total Current Year Jurisdictional Deferred Tax Adjustments, A-5, Page 4 of 5		<u>(103,526)</u>	
11				
12	(15) These adjustments are to eliminate ADIT balances related to Wind Credits which are carried on the			
13	Corporate books.			
14	(16) There are miscellaneous rounding adjustments in the ADIT Accts to balance.			
15				
16	(17) Acct 283 @ 12/31/05 had Corporate amounts in it that were not separated from the Utility portion while the 12/3106 balance contains			
17	only Utility amounts. There is \$10 remaining in the Corporate Acct 283. An adjustment of \$10 is needed to offset current year adjustment			
18	amounts to Acct 283, in essence to "set-up" the corporate balance at 12/31/07.			

Otter Tail Power Company
DEFERRED INCOME TAX EXPENSE
Actual Year 2007

Prepared by: kas
Reviewed by: pjb

	(A)	(B)	(C)	(D)	(E)
Line No.	Deferred Tax Expense - debit/(credit)	Federal	Minnesota	North Dakota	Total
1	Per Year End Tax Accrual, Footnote 4, Page 1 Of 1	(1) 2,746,969	369,540	233,851	3,350,360
2					
3	Less: Jurisdictional Deferred Income Tax Items	(2) (86,223)	(10,674)	(6,629)	(103,526)
4		2,833,192	380,214	240,480	3,453,886
5					
6	Less Prior Period Adjustments	(2) 2,494,145	279,529	188,781	2,962,455
7	Systemwide Current Year Deferred Tax Expense	339,047	100,685	51,699	491,431
8					
9	Adjustments:				
10	Amount on Corporate Books	(2)			0
11	FAS 87 Deferred taxes on Pension loss	(4)			
12	Current Year Coss Utility Deferred Tax Expense	339,047	100,685	51,699	491,431
13					
14					
15	Less: Items South Dakota Flows Through - Current	(3) 587,347	68,662	53,223	709,232
16	Less: Items South Dakota Flows Through - Prior	(4) 0	0	0	0
17	Total Items South Dakota Flows Through	587,347	68,662	53,223	709,232
18					
19	All Other Deferred Income Tax Expense	(248,300)	32,023	(1,524)	(217,801)

- (1) Year-End Tax Accrual W/P Footnote 4, Page 1 Of 1
 (2) A-5, Page 4 Of 5
 (3) A-5, Page 5 Of 5
 (4) Year-End Tax Accrual W/P Footnote 6, Page 1 Of 6.
 (5) Agrees with fn (7), A-5, page 2 of 5

Prepared by: kas
Reviewed by: pjb

Otter Tail Power Company
DEFERRED INCOME TAX CALCULATION
Actual Year 2007

Line No.	(A)	(B)	(C)	(D)	(E)	
	Recap Of 2006 Deferred Income Tax Expense::		Federal	Minnesota	No Dakota	Total
1	Prior Period Adjustments:					
2	Depreciation	(1)	(35,148)	(5,773)	(3,989)	(44,910)
3	Net Overhead Costs	(1)	(1,526)	(187)	(127)	(1,840)
4	Other Costs Capitalized	(1)	2,530,819	285,489	192,897	3,009,205
5	Total Prior Period Adjustments		2,494,145	279,529	188,781	2,962,455
6	Current Year Activity:					
7	Depreciation	(2)	3,313,035	420,115	273,218	4,006,368
8	Cost To Remove - Gross	(2)	0	0	0	0
9	Interest Capitalized On Construction	(2)	(479,950)	(52,904)	(36,345)	(569,199)
10	Afdc On Debt	(2)	613,959	67,744	49,946	731,649
11	Overhead Costs Capitalized - South Dakota Flowthru	(2)	23,951	0	0	23,951
12	ADR Repair Allowance	(2)	99,889	10,874	7,541	118,304
13	SEC 174 R&E Deductions	(2)	(22,235)	(2,508)	(1,695)	(26,438)
14	Overheads Reversing - Gross	(2)	(27,641)	(3,870)	(558)	(32,069)
15	Overheads Reversing - South Dakota Flowthru	(2)	2,263	0	0	2,263
16	Other Costs Capitalized:					
17	Minnesota Cip Tracker Account	(2), (3)	(86,977)	(10,936)	(6,838)	(104,751)
18	Reserve For Loan Pool	(2)	(192)	(22)	(15)	(229)
19	Gain On Bonds Reversal - Previously Booked	(2)	0	0	0	0
20	Reserve for bad debts	(2)	(7,609)	(858)	(580)	(9,047)
21	CIAC - capitalized	(2)	20,462	2,699	1,632	24,793
22	Amortization Of Big Stone Deferred Taxes	(2)	(5,655)	(705)	(319)	(6,679)
23	Capitalized A&G expenses	(2)	(386,506)	(40,748)	(28,987)	(456,241)
24	Stock incentives	(2)	(31)	(4)	(3)	(38)
25	Mapleton Industrial Park Land Writeoff	(2)	11,448	1,468	905	13,821
26	Asbestos removal	(2)	1,925	285	154	2,364
27	Accrued vacation pay	(2)	(28,842)	(3,253)	(2,199)	(34,294)
28	Capitalized customer rebates	(2)	(6,933)	(782)	(528)	(8,243)
29	Excess Tax Over Book Pensions	(2)	(1,479,882)	(166,938)	(112,796)	(1,759,616)
30	Reserves: Reversing; Storm Damage	(2)	0	0	0	0
31	Reserves: Reversing; Exec. Supp. Pension	(2)	352,637	43,749	27,446	423,832
32	Reserves: Reversing; Post Retirement Benefits	(2)	671,277	83,536	52,296	807,109
33	Reserves: Reversing; Post Employment Benefits	(2)	85,777	9,991	6,588	102,356
34	Reserves: Reversing; Injuries and Damages	(2)	(2,767)	(312)	(211)	(3,290)
35	Reserves: Reversing; MN Worker's Comp	(2)	97,514	11,000	7,432	115,946
36	Reserves: Originating Storm Damage	(2)	0	0	0	0
37	Reserves: Originating Exec. Supp. Pension	(2)	(880,195)	(99,290)	(67,088)	(1,046,573)
38	Reserves: Originating; Post Retirement Benefits	(2)	(1,437,306)	(162,135)	(109,551)	(1,708,992)
39	Reserves: Originating; Post Employment Benefits	(2)	(76,185)	(8,594)	(5,807)	(90,586)
40	Reserves: Originating; Injuries and Damages	(2)	0	0	0	0
41	Reserves: Originating; MN Worker's Comp	(2)	(94,890)	(10,704)	(7,232)	(112,826)
42	Amort Medicare Part D	(2)	(45,112)	0	(3,439)	(48,551)
43	Deferred Settlement	(2)	27,595	3,113	2,103	32,811
44	All Other	(2)	0	0	0	0
45	Total Current Year	(2)	252,824	90,011	45,070	387,905
46						
47	Less: Jurisdictional ADIT Items not used in COSS:					
48	Minnesota Cip Tracker Account	(3)(2)	(86,977)	(10,936)	(6,838)	(104,751)
49	Asbestos removal (IRS 93 audit)	(2)	1,925	285	154	2,364
50	Customer rebates (IRS 93 audit)	(2)	(6,933)	(782)	(528)	(8,243)
51	Stock incentives	(2)	(31)	(4)	(3)	(38)
52	Stock Options	(6)				0
53	Mapleton Industrial Park Land Writeoff	(2)	11,448	1,468	905	13,821
54	Amortization Of Big Stone Deferred Taxes	(2)	(5,655)	(705)	(319)	(6,679)
55						
56	Total Jurisdictional ADIT Items		(86,223)	(10,674)	(6,629)	(103,526)
57						
58	Current Year Systemwide Entries To Deferred Tax Expense		339,047	100,685	51,699	491,431
59						

- (1) Year End Tax Accrual W/P Footnote 6, Page 2 Of 2
- (2) Year End Tax Accrual W/P Footnote 5, Page 1 Of 2
- (3) Minnesota CIP Tracker Account - Minnesota Adjustment 3 will handle the deferred income tax, the accumulated deferred income tax and the Schedule M portions of this item. For book purposes, this timing difference is assumed to reverse over the tax life of the property. Because the additional depreciation on Schedule M was not jurisdictional, we will ignore the reversal shown above for jurisdictional purposes. Technically, we should treat the reversal as a jurisdictional item, but leaving it as a systemwide number will create a wash with the treatment of the additional depreciation as a systemwide number on Schedule M. ADIT difference is not material.
- (4) Agrees to A-5, page 2 of 5, fn (7)
- (5) N/A
- (6) Per Sr. Tax Accountant
- The purpose of treating the above items as jurisdictional adjustments is that our systemwide ADIT allocation procedures do not handle jurisdictional deferred tax items. The adjustments assigns the proper jurisdictional deferred tax amounts by determining the amount of deferred taxes that should be allocated to a jurisdiction and then gross up the jurisdictional amount (using the latest factors available) to arrive at a systemwide deferred tax number for that jurisdiction.

Prepared by: kas
Reviewed by: pjb

Otter Tail Power Company
SOUTH DAKOTA FLOW THROUGH ITEMS
Actual Year 2007

	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	South Dakota Flow Through Items:		Federal	Minnesota	North Dakota	Total
1	Cost To Remove	(1)	0	0	0	0
2	AFUDC On Debt	(1)	187,416	19,628	17,436	224,480
3	Interest Capitalized On Construction	(1)	479,950	52,904	36,345	569,199
4	Overhead Costs Reversing	(1)	(27,641)	(3,870)	(558)	(32,069)
5	Gain On Bonds Reversal	(1)	0	0	0	0
6	12/31 TOTAL		639,725	68,662	53,223	761,610
7	Less South Dakota Flowthru	(2)	52,378			52,378
8	Total Excluding South Dakota Flowthru		587,347	68,662	53,223	709,232

9 (1) Per Year End Tax Accrual W/P DEF 6, Page 1 of 1; detail on DEF 7, page 1 of 2

10 (2) Per Year End Tax Accrual W/P DEF 6, Page 1 Of 1. Percentage Of Federal Allocated To South Dakota Was

8.1875420%

Otter Tail Power Company Customer Advances (Prepaid Electric Revenue) Actual 12 Months Ending December 31, 2007

Prepared by:	kas
Checked by:	pjb

	(A)	(B)	(C)	(D)
Line No.	Acct # 253.0/2590.3000			Monthly Balances
1	December	End	2006	(110,419.29)
2	January	End	2007	(104,240.75)
3		Beg	2007	(104,240.75)
4	February	End	2007	(102,132.25)
5		Beg	2007	(102,132.25)
6	March	End	2007	(104,632.25)
7		Beg	2007	(104,632.25)
8	April	End	2007	(94,632.25)
9		Beg	2007	(94,632.25)
10	May	End	2007	(112,746.76)
11		Beg	2007	(112,746.76)
12	June	End	2007	(134,046.76)
13		Beg	2007	(134,046.76)
14	July	End	2007	(132,909.45)
15		Beg	2007	(132,909.45)
16	August	End	2007	(141,449.95)
17		Beg	2007	(141,449.95)
18	September	End	2007	(140,831.33)
19		Beg	2007	(140,831.33)
20	October	End	2007	(157,363.52)
21		Beg	2007	(157,363.52)
22	November	End	2007	(171,438.52)
23		Beg	2007	(171,438.52)
24	December	End	2007	(171,438.52)
25	Total			(3,074,705.39)
26	Average			(129,098.58)

Source: FERC GL Account data file

Prepared by: kas

Checked by: pjb

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
Line No.	YEAR	MONTH	CO	BU	CC	ACCT	SUB	ACTY	PROJ	FERC1	FERC2	YTD-BAL	CM-BAL
1	2006	12	100	30	0	2590	3000	0	0	25300	0	(110,419.29)	400.00
2	2007	1	100	30	0	2590	3000	0	0	25300	0	(104,240.75)	6,178.54
3	2007	2	100	30	0	2590	3000	0	0	25300	0	(102,132.25)	2,108.50
4	2007	3	100	30	0	2590	3000	0	0	25300	0	(104,632.25)	(2,500.00)
5	2007	4	100	30	0	2590	3000	0	0	25300	0	(94,632.25)	10,000.00
6	2007	5	100	30	0	2590	3000	0	0	25300	0	(112,746.76)	(18,114.51)
7	2007	6	100	30	0	2590	3000	0	0	25300	0	(134,046.76)	(21,300.00)
8	2007	7	100	30	0	2590	3000	0	0	25300	0	(132,909.45)	1,137.31
9	2007	8	100	30	0	2590	3000	0	0	25300	0	(141,449.95)	(8,540.50)
10	2007	9	100	30	0	2590	3000	0	0	25300	0	(140,831.33)	618.62
11	2007	10	100	30	0	2590	3000	0	0	25300	0	(157,363.52)	(16,532.19)
12	2007	11	100	30	0	2590	3000	0	0	25300	0	(171,438.52)	(14,075.00)
13	2007	12	100	30	0	2590	3000	0	0	25300	0	(171,438.52)	-

Source: FERC data base

Prepared By: kas
Reviewed By: pjb

Otter Tail Power Company Cash Working Capital - Cost of Energy Adjustment Revenues <i>Actual 12 Months Ending 12/31/07</i>

Line No.	(A)	(B)	(C)
	<u>Jurisdiction:</u>	Cost of Energy Adjustment Revenues	
1	Minnesota	18,823,676	(1)
2			
3	North Dakota	17,275,360	(1)
4			
5	South Dakota	4,261,508	(1)
6			
7	FERC	36,458	(1)
8			
9	Total	40,397,002	
(1) Page 1a of 9.			

Prepared By: kas
Reviewed By: pjb

Otter Tail Power Company
Cash Working Capital - Cost of Energy Revenues
[Actual 12 Months Ending 12/31/07](#)

	(A)	(B)	(C)
Line No.	YEAR	STATE	Sum of COE Adj
1	2007	MN	\$18,823,676
2	2007	ND	\$17,275,360
3	2007	SD	\$4,261,508
4			<u>\$40,360,543.84</u>
5		FERC	<u>\$36,458</u>
6		Total	<u>\$ 40,397,001.63</u>
7			

From Page 4 of the 2007 stat book from Jill's folder

Prepared By: kas
Reviewed By: pjb

Otter Tail Power Company
Coal & Oil Expense
Actual 12 Months Ending 12/31/07

Line No.	(A)	(B)	(C)
1		Lignite/Subituminous Consumed	Oil/Nat Gas/TDF Consumed
2			
3	Hoot Lake	19,228,385 (1)	96,684 (1)
4			
5	Coyote (OTP Share)	12,444,885 (1)	618,097 (1)
6			
7	Big Stone (OTP Share)	21,456,846	400,647 (1)
8			
9	All IC's (A/C 547)	0	6,236,150 (1)
10			
11	Total	53,130,116	7,351,578
12			
13			
14	Total Oil Natural Gas and Lignite	59,171,635	60,481,694
15			
16			
17	Reconciliation:		
18	A/C 5010.1000 Lignite	(1)	12,444,885
19	A/C 5010.3000 TDF	(1)	84,440
20	A/C 5010.2000 Subbituminous	(1)	40,685,231
21	A/C 5010.5000 Fuel Oil	(1)	2,737,136
22	A/C 5010.6000 RRM	(1)	765
23	A/C 5010.7000 Natural Gas	(1)	4,529,237
24	Total		60,481,694
25			
26	FERC Financial Statement		
27	Production Fuel		60,481,694
28			0
29			60,481,694
30	Unexplained difference from FERC F/S		(0)
31	Unexplained difference from above		0
	(1) 12/31/07 FERC Trial Balance Detail found on Page 2a.		

Otter Tail Power Company
Coal & Oil Expense
Actual 12 Months Ending 12/31/07

Prepared By: kas
Reviewed By: pjb

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
	YEAR	MONTH	CO	BU	CC	ACCT	SUB	ACTY	PROJ	FERC1	FERC2	SumOfBalance		Total
1	2007	12	100	10	1000	5010	1000	560	0	40100	50101	(\$226,707.00)	Coyote	\$60,481,693.64
2	2007	12	100	10	1000	5010	2000	560	0	40100	50101	(\$193,698.00)	Bigstone	Difference
3	(Big Stone and Coyote GO Expenses charged to Fuel)												(\$420,405.00)	\$60,481,693.64
4														
5	2007	12	100	010	1020	5010	2000	0560	101020	40100	50101	\$19,228,385.14		
6	Hoot Lake Plant Subbituminous													\$19,228,385.14
7	2007	12	100	010	1020	5010	5000	0560	101020	40100	50101	\$96,684.28		
8	Hoot Lake Plant Fuel Oil													\$96,684.28
9	Total Hoot Lake Plant Fuel Costs													\$19,325,069.42
10														
11	2007	12	100	010	1130	5010	2000	0560	101130	40100	50101	\$40,167,984.36		
12	2007	12	100	010	1130	5010	2000	0580	101130	40100	50600	(\$0.00)		
13	2007	12	100	010	1190	5010	2000	0560	000000	40100	50101	(\$18,517,440.79)		
14	2007	12	100	010	1190	5010	2000	0580	000000	40100	50600	\$0.00		
15	Big Stone GO Expenses from above													(\$193,698.00)
16	Big Stone Subbituminous													\$21,456,845.57
17														
18	2007	12	100	010	1130	5010	3000	0560	101130	40100	50101	\$156,660.37		
19	2007	12	100	010	1190	5010	3000	0560	000000	40100	50101	(\$72,220.41)		
20	Big Stone TDF													\$84,439.96
21														
22	2007	12	100	010	1130	5010	5000	0560	101130	40100	50101	\$585,235.38		
23	2007	12	100	010	1190	5010	5000	0560	000000	40100	50101	(\$269,793.51)		
24	Big Stone Fuel Oil													\$315,441.87
25														
26	2007	12	100	010	1130	5010	6000	0560	101130	40100	50101	\$1,418.94		
27	2007	12	100	010	1190	5010	6000	0560	000000	40100	50101	(\$654.12)		
28	Big Stone RRM													\$764.82
29	Big Stone Total													\$21,857,492.22
30														
31	2007	12	100	010	1230	5010	1000	0560	101230	40100	50101	\$36,204,548.63		
32	2007	12	100	010	1290	5010	1000	0560	000000	40100	50101	(\$23,532,956.62)		
33	Coyote GO Expenses from above													(\$226,707.00)
34	Coyote Lignite													\$12,444,885.01
35														
36	2007	12	100	010	1230	5010	5000	0560	101230	40100	50101	\$1,765,991.01		
37	2007	12	100	010	1290	5010	5000	0560	000000	40100	50101	(\$1,147,894.19)		
38	Coyote Fuel Oil													\$618,096.82
39														
40	2007	12	100	010	1400	5010	5000	0560	101400	40100	54700	\$1,310,058.74		
41	2007	12	100	010	1410	5010	5000	0560	101410	40100	54700	\$375,093.37		
42	2007	12	100	010	1440	5010	5000	0560	101440	40100	54700	\$21,761.15		
43	IC Fuel Oil													\$1,706,913.26
44														
45	2007	12	100	010	1440	5010	7000	0560	101440	40100	54700	\$4,529,236.91		
46	IC Natural Gas													\$4,529,236.91
47	Total IC													\$6,236,150.17
48														
49														
														\$60,481,693.64 check by plant

Prepared By: kas
Reviewed By: pjb

Otter Tail Power Company
Coal Conversion Tax
[Actual 12 Months Ending 12/31/07](#)

Line No.	(A)	(B)	(C)
		<u>Amount</u>	<u>Percentage</u>
1	General Taxes	\$9,411,607 (1)	100.0000%
2			
3	Coal Conversion Taxes	753,852 (2)	8.0098%
4			
5	All Other	<u>\$8,657,755</u>	<u>91.9902%</u>
6			
7			
8	(1)	12/07 FERC Financial Statement	
9	(2)	FERC Form 1 Page 262 - 263	
10			
11			
12			

Otter Tail Power Company Cash Balances Actual 12 Months Ending 12/31/07

Prepared By:	kas
Reviewed By:	pjb

Line No.	(A)	(B)	(C)
	<u>Minimum Bank Balances:</u>	Amount	Reference
1	Dec '06	23,603	(4)
2	Jan	8,400	(5)
3	Feb	8,400	(5)
4	Mar	8,400	(5)
5	Apr	8,400	(5)
6	May	8,400	(5)
7	Jun	8,400	(5)
8	Jul	8,700	(5)
9	Aug	8,700	(5)
10	Sep	7,700	(2)
11	Oct	7,700	(2)
12	Nov	7,700	(2)
13	Dec	7,700	(2)
14			
15	Total	122,203	
16			
17	Average	9,400	
18			
19			
20	<u>Compensating Balances:</u>	None	(1)
21			
22	<u>Minimum Average Daily Bank Balances:</u>	0	(3)
23			
24			
25	Total Cash Balances:	9,400	
26			

27	
28	(1) Per Cash Mgmt/Treasury Dept.
29	(2) A-7 , Page 5 of 9
30	(3) A-7 , Page 4a of 19
31	(4) Per 2006 COSS Workpaper A-7, Pg 4.
32	(5) Per the asterisked items on the bottom of A-7, Page 5; the
33	balances for each month-end have been adjusted to actual.

Otter Tail Power Company Cash Balances <u>Actual 12 Months Ending 12/31/07</u>

Prepared By: kas
Reviewed By: pjb

Line No.	(A)	(B)	(C)
	<u>Minimum Daily Bank Balances:</u>	Amount	Reference
1	Dec	0	(1)
2	Jan	0	(1)
3	Feb	0	(1)
4	Mar	0	(1)
5	Apr	0	(1)
6	May	0	(1)
7	Jun	0	(1)
8	Jul	0	(1)
9	Aug	0	(1)
10	Sep	0	(1)
11	Oct	0	(1)
12	Nov	0	(1)
13	Dec	0	(1)
14			
15	Total	0	
16			
17	Average	0	
18			
19			
20			
21	(1) Per e-mail from Sue Vukonich, Treasury Dept for 2006 COSS. See email on Page 4b.		
22			
23			
24			

kas
pjb

Otter Tail Power Company
Minimum Bank Balances
Actual 12 Months Ending 12/31/07

(A)

(B)

(C)

(D)

MINIMUM BANK BALANCES

Line No.	CUSTOMER SERVICE CENTERS	BANK	TOWN	MINIMUM BALANCE
1	FERGUS FALLS	BANK OF THE WEST*	FERGUS FALLS	closed 1/3/07
2	DEVILS LAKE			
3	JAMESTOWN	BANK FORWARD**	JAMESTOWN	100
4	MORRIS	FIRST FEDERAL SAVINGS	MORRIS	2,500
5	OAKES	STARION FINANCIAL	OAKES	500
6		SARGENT COUNTY BANK	FORMAN	500
7		BREMER BANK	LISBON	500
8	WAHPETON			
9	RUGBY	MERCHANTS BANK	RUGBY	1,000
10		FIRST SECURITY BANK	CANBY	500
11	BEMIDJI	FIRST NATIONAL BANK	BEMIDJI	500
12	CROOKSTON	BREMER BANK	CROOKSTON	500
13	GARRISON	GARRISON STATE BANK	GARRISON	500
14	MILBANK	FIRST BANK & TRUST	MILBANK	300
15		GREAT WESTERN BANK***	MILBANK	closed in 2007
16				
17	MANITOBA HYDRO ACCT.	US BANK****		300
18				
19	TOTAL			7,700

*The Bank of the West account in Fergus Falls was closed on January 3, 2007.

**Security State Bank of Jamestown became Bank Forward during 2007.

***The Great Western Bank account was closed in September, 2007. Minimum Balance of \$1,000 while open.

****The US Bank Manitoba Hydro Margin Account was opened in July, 2007.

NOTE: A joint checking account was opened on December 1, 2005, with the seven partners of the Big Stone II Project. The balance at December 31, 2007, was \$109,141.06. This account is funded by the partners as bills are paid for the project. The balance is swept daily to a Repurchase Agreement account where it earns interest.

CashMgmt\Cash\MinimumBankBalance
PMF

Prepared By: kas
Reviewed By: pjb

Otter Tail Power Company
Working Funds
Actual 12 Months Ending 12/31/07

	(A)	(B)	(C)	(D)
Line No.	Working Funds - (Accounts 135.0, 135.1, 135.2, 135.3, 135.4/1075.0000)			Monthly Balances
1	December	End	2006	22,880
2	January	End	2007	22,880
3		Beg	2007	22,880
4	February	End	2007	22,880
5		Beg	2007	22,880
6	March	End	2007	22,880
7		Beg	2007	22,880
8	April	End	2007	22,630
9		Beg	2007	22,630
10	May	End	2007	23,130
11		Beg	2007	23,130
12	June	End	2007	22,630
13		Beg	2007	22,630
14	July	End	2007	22,630
15		Beg	2007	22,630
16	August	End	2007	22,630
17		Beg	2007	22,630
18	September	End	2007	22,405
19		Beg	2007	22,405
20	October	End	2007	22,405
21		Beg	2007	22,405
22	November	End	2007	22,405
23		Beg	2007	22,405
24	December	End	2007	22,405
25	Total			544,295
26	Average			22,679
Source of Data: Monthly Financial Statements, Page 2.				

Prepared By: kas
Reviewed By: pjb

Otter Tail Power Company
Special Deposits
Actual 12 Months Ending 12/31/07

	(A)	(B)	(C)	(D)
Line No.	Special Accounts - (Accounts 132.0, 134.0/1050.0000)			Monthly Balances
1	December	End	2006	1,300,137
2	January	End	2007	1,030,340
3		Beg	2007	1,030,340
4	February	End	2007	847,640
5		Beg	2007	847,640
6	March	End	2007	681,582
7		Beg	2007	681,582
8	April	End	2007	695,560
9		Beg	2007	695,560
10	May	End	2007	1,193,961
11		Beg	2007	1,193,961
12	June	End	2007	1,039,914
13		Beg	2007	1,039,914
14	July	End	2007	674,883
15		Beg	2007	674,883
16	August	End	2007	577,717
17		Beg	2007	577,717
18	September	End	2007	500,262
19		Beg	2007	500,262
20	October	End	2007	569,884
21		Beg	2007	569,884
22	November	End	2007	468,337
23		Beg	2007	468,337
24	December	End	2007	1,077,734
25	Total			18,938,031
26	Average			789,085
Source of Data: Monthly Financial Statements, Page 2. Special deposits related to BSP II				

Prepared By: kas
Reviewed By: pjb

Otter Tail Power Company
Tax Collections Available
Actual 12 Months Ending 12/31/07

Line No.	(A)	(B)
1	Employee FICA Withholding	3,998,989 (1)
2		
3	Employee Federal Withholding	6,820,822 (1)
4		
5	Employee State Withholding - Minnesota	1,635,219 (1)
6		
7	Employee State Withholding - North Dakota	256,507 (1)
8		
9		
10	<u>Customer Sales Tax:</u>	
11	Minnesota	5,813,859 (2)
12	North Dakota	2,020 (2)
13	South Dakota	1,212,766 (2)
14		
15	Total Sales Tax	7,028,645
16		
17		
18	Franchise Taxes	722,428 (2)

(1) Per "Payroll Info-07" file located in 2007 Actual Workpaper Folder.
(2) A-7; Page 9 of 9

Otter Tail Power Company
Tax Collections Available
Actual 12 Months Ending 12/31/07

Prepared By: kas
Reviewed By: pjb

	(A)	(B)	(C)
Line No.	Sales taxes		
	MN	ND	SD
1	\$ 5,771,711.28	\$ 1,685.55	\$ 923,134.88
2	\$ 42,147.47	\$ 2.07	\$ 13,441.33
3		\$ 3.84	\$ 83,151.75
4		\$ 1.92	\$ 36,699.79
5		\$ 2.88	\$ 10,447.08
6		\$ 3.64	\$ 8,110.94
7		\$ 11.52	\$ 18,620.89
8		\$ 32.66	\$ 1,956.15
9		\$ 11.52	\$ 7,163.35
10		\$ 10.82	\$ 1,375.82
11		\$ 1.92	\$ 1,289.91
12		\$ 14.48	\$ 1,166.49
13		\$ 1.92	\$ 17,800.83
14		\$ 5.29	\$ 2,443.83
15		\$ 2.69	\$ 9,159.20
16		\$ 14.41	\$ 22,320.61
17		\$ 1.92	\$ 1,859.23
18		\$ 9.94	\$ 5,601.54
19		\$ 13.78	\$ 3,266.59
20		\$ 3.20	\$ 21,845.58
21		\$ 0.97	\$ 9,585.34
22		\$ 2.41	\$ 2,848.24
23		\$ 111.08	\$ 3,152.87
24		\$ 2.10	\$ 927.69
25		\$ 14.40	\$ 1,943.58
26		\$ 2.97	\$ 2,275.79
27		\$ 1.20	\$ 1,176.67
28		\$ 11.52	
29		\$ 13.15	
30		\$ 2.88	
31		\$ 1.92	
32		\$ 7.70	
33		\$ 1.92	
34		\$ 1.92	
35		\$ 3.23	
36		\$ 1.92	
37		\$ 2.98	
38	\$5,813,858.75	\$2,020.24	\$1,212,765.97
39			
40	Franchise taxes	\$ 722,427.68	(1)

Source: CIS340 Revenue Report from last business day of the year
received from Jill Bjorgum

Prepared By: kas
Reviewed By: pjb

Otter Tail Power Company
Fuel Stocks
Actual 12 Months Ending December 31, 2007

	(A)	(B)	(C)	(D)	(E)	(F)
Line No.				Coal Stocks	Oil & Other** Stocks	Total
1	December	End	2006	5,577,603	1,890,034	7,467,637
2	January	End	2007	5,585,064	1,797,168	7,382,232
3		Beg	2007	5,585,064	1,797,168	7,382,232
4	February	End	2007	5,538,730	1,812,245	7,350,975
5		Beg	2007	5,538,730	1,812,245	7,350,975
6	March	End	2007	5,258,471	1,798,401	7,056,872
7		Beg	2007	5,258,471	1,798,401	7,056,872
8	April	End	2007	4,700,279	1,773,161	6,473,440
9		Beg	2007	4,700,279	1,773,161	6,473,440
10	May	End	2007	5,278,873	1,876,063	7,154,936
11		Beg	2007	5,278,873	1,876,063	7,154,936
12	June	End	2007	5,465,468	1,721,028	7,186,496
13		Beg	2007	5,465,468	1,721,028	7,186,496
14	July	End	2007	5,639,803	1,807,213	7,447,016
15		Beg	2007	5,639,803	1,807,213	7,447,016
16	August	End	2007	5,895,135	2,033,377	7,928,512
17		Beg	2007	5,895,135	2,033,377	7,928,512
18	September	End	2007	6,097,435	2,145,791	8,243,226
19		Beg	2007	6,097,435	2,145,791	8,243,226
20	October	End	2007	6,132,400	2,345,837	8,478,237
21		Beg	2007	6,132,400	2,345,837	8,478,237
22	November	End	2007	6,598,964	2,233,611	8,832,575
23		Beg	2007	6,598,964	2,233,611	8,832,575
24	December	End	2007	7,033,989	1,764,591	8,798,580
25	Total			136,992,836	46,342,415	183,335,251
26	Average			5,708,035	1,930,934	7,638,969

**Propane, Tire Derived Fuel, Renewable Resource Fuel and Natural Gas

Source: Appropriate Month Financial Statement, Page 9

Prepared by: kas
Reviewed by: pjb

Otter Tail Power Company Retail Revenue Actual 12 Months Ending 12/31/07

Line No.	(A)	(B)
1	Minnesota	134,836,006 (1)
2		
3	North Dakota	108,472,410 (2)
4		
5	South Dakota	25,389,754 (3)
6		
7	TOTAL RETAIL REVENUE	<u>268,698,170</u>
8		
9		
10		
11		
12		
13		
14	(1) 2007 Regulatory Services Statistical Report, Page 5	135,276,121
15	Plus: Unbilled Revenue, incremental change, Stat Report, Page 5	(440,115)
16	MINNESOTA REVENUE FOR COSS	<u>134,836,006</u>
17		
18	(2) 2007 Regulatory Services Statistical Report, Page 5	108,263,131
19	Plus: Unbilled Revenue, incremental change, Stat Report, Page 5	209,279
20	NORTH DAKOTA REVENUE FOR COSS	<u>108,472,410</u>
21		
22	(3) 2007 Regulatory Services Statistical Report, Page 5	25,471,640
23	Plus: Unbilled Revenue, incremental change, Stat Report, Page 5	(81,886)
24	SOUTH DAKOTA REVENUE FOR COSS	<u>25,389,754</u>
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		

Prepared by: kas
Reviewed by: plb

Otter Tail Power Company
Billed Retail Sales and Revenue
Actual 12 Months Ending 12/31/07

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	Group	Load Research Groups	ORIG Rate Groups	1997 Rate Groups	Sales MN	Revenue MN	Sales ND	Revenue ND	Sales SD	Revenue SD
1										
2										
3										
4										
5	Residential	RES	11 & 12	11	403,762,151	33,472,558	361,529,823	30,874,913	85,368,684	7,007,855
6	Residential EH RDC	RDC	16	12	57,600,110	3,547,933	92,243,607	5,390,337	11,174,328	678,552
7	TOTAL RESIDENTIAL				461,362,261	37,020,492	453,773,430	36,265,250	96,543,012	7,686,407
8										
9	FARM	FAR	21,22,26	21,22,23	32,608,209	2,203,170	23,613,952	1,590,979	6,943,577	506,221
10										
11	Gen. Serv.	LGS & SGS	31,41,32,42	31,41						
12	Gen. Serv. (CEC)	CDC & CTU	36,46	36,48						
13										
14	TOTAL GENERAL SERVICE				328,085,601	26,959,238	417,178,604	33,768,335	87,056,185	6,661,131
15										
16	Lg. Gen. Ser. Sec.	GSS	47,48	43						
17	Lg. Gen. Ser. Pri.	GSP	47,48	42	594,839,640	34,589,405	375,232,940	22,240,148	157,821,566	8,334,741
18	Pipelines	GST	62	62	512,500,361	24,895,109	6,892,800	408,595	-	-
19	Ladish	GSP	63	63	-	-	74,019,900	4,135,105	-	-
20	TOTAL LG. GEN. SER.				1,107,340,001	59,484,514	456,145,640	26,783,847	157,821,566	8,334,741
21										
22	IRRIGATION	IRR	27,37	29,37	5,396,845	314,399	659,077	45,674	367,542	23,983
23	ST. & AREA LTG	SLT & ALT	17,28,38,50,61	17,28,38,49,61	20,262,508	2,390,538	22,848,389	2,091,712	4,448,103	535,045
24	OPA	OPA	51,52	51,52	20,926,558	1,217,157	17,002,170	961,697	3,817,672	213,851
25	CONTR. WATER HTG	WHR	15,25,35,45	13,24,34,46	25,189,124	1,417,501	19,848,693	1,177,185	6,703,070	362,058
26	CTR. SER. (INT.)	SDF, LDF	13,23,33,43,49	14,15,25,26,32,33,44,45	108,284,749	3,481,346	162,511,270	4,737,220	28,820,666	959,329
27	CONTR. SER. (DEF.)	HST	14,24,34,44	16,27,35,47	18,407,119	787,766	19,239,254	841,231	4,828,790	198,874
28										
29	Total				2,127,862,975	135,276,121	1,592,820,479	108,263,131	397,350,183	25,471,640
30										
31					2,127,862,975	135,276,121	1,592,820,479	108,263,131	397,350,183	25,471,640
32										

Detail for input summary
B summary p 7 of 7

Prepared by: kas
Reviewed by: pjb

Otter Tail Power Company
Sales For Resale
Actual 12 Months Ending 12/31/07

Line No.	(A)	(B)	(C)	(D)
	<u>Total Sales For Resale:</u>	Detail	Totals	Input Summary line
1	Minnesota (1)	190,431		398
2	South Dakota (1)	21,001		399
3	North Dakota (1)	0		
4	Asset based Wholesale Sales (2)	20,133,608		406
5	Total Sales For Resale		20,345,040	
6				
7				
8	(1) Statistical Report, Page 264, Wholesale MN & SD city totals; Also, combined amount ties to Dec F/S Pg 10 "Wholesale Revenue"			
9	(2) Wholesale Electric Operating Revenues p 5 F/S less the MN, ND and SD sales for resale.			
10				

Otter Tail Power Company
Other Electric Revenues
Actual Year 2007

Prepared by: kas
Reviewed by: pjb

Line No.	(A)	(B)	(C)	(D)	(E)
1	Late Charges (450)				
2	MN	294,442.98	(1)		
3	ND	170,779.34	(1)		
4	SD	80,104.02	(1)		
5	Total Late Charges			545,326	(2)
6	Connection Fees (452.1)				
7	MN	190,817	(1)		
8	ND	89,754	(1)		
9	SD	35,174	(1)		
10	Total Connection Fees			315,745	(2)
11	Loan - Series A	642,827	(3)		
12	Loan - Series B	1,175	(3)		
13		(20,657)	(3)		
14		11,846	(3)		
15				635,191	(2)
16	Integrated Transmission Deficiency Payments (456.3)			2,589,668	(2)
17				3,651,858	(2)
18	Wheeling (456.5)				
19	MN	207,155	(1)		
20	ND	216,350	(1)		
21	SD	9,518	(1)		
22	Total Wheeling (all FERC)			433,023	(2)
23	MISO Tariff Revenue	2,205,221	(2)		
24	MAPP Transmission service charge (456.4)	25,173	(2)		
25	Load Control & Dispatch (456.6)	2,229,532	(2)		
26	Total Load Control & Dispatch, MISO & MAPF			4,459,926	
27	Miscellaneous Services (452.0)			34,025	(2)
28	Sub-Total Other Electric Revenues			12,664,762	(6)
29	Interest income from loan pools & economic development				
30	MN	66,381	(4)		
31	ND	9,642	(4)		
32	SD	872	(4)		
33	Total interest income			76,895	
34	Gain on sale of emission allowances (a/c 411.8)			129,650	(7)
35	Total Other Electric Revenues			12,871,306	

(1) B-3, page 2 of 6 (W/P from Regulatory Transaction Specialist)

(2) 12/07 Monthly Financial Statement, page 11

(3) B-3, page 4 of 6

(4) Interest Revenues B-3, Page 3 of 6

(5) N/A

(6) Reconciliation with FERC Financial Statement:

FERC financial statement

Difference

(7) FERC Trial Balance or Database

12,664,762

12,664,762

(0)

NEW ACCT. NO. 100.070.0000.

Prepared by:	kas
Reviewed by:	pjb

Line No.	(A) WHEELING	(B) MINNESOTA	(C) NORTH DAKOTA	(D) SOUTH DAKOTA	(E) TOTAL
1	FERGUS FALLS CUSTOMER SERVICE CTR	\$8,065.44			
2	DEVILS LAKE CUSTOMER SERVICE CTR		\$41,997.58		
3	WAHPETON CUSTOMER SERVICE CTR		\$92,259.10		
4	LANGDON CUSTOMER SERVICE CTR		\$25,010.81		
5	RUGBY CUSTOMER SERVICE CTR		\$11,033.84		
6	CROOKSTON DIVISION	\$51,226.37			
7	MILBANK DIVISION			\$9,517.64	
8	WESTERN AREA POWER ADMINISTRATION		\$1,056.40		
9	MINNKOTA POWER CO-OP	\$157,235.64	\$44,238.10		
10	Loan - Series A	-\$9,372.10	\$754.11		
11	Loan - Series B	\$207,155.35	\$216,349.94	\$9,517.64	\$433,022.93
12					
13					
14					
15			\$809,646.03		
16		\$116,367.56		\$41,262.46	
17	EAST RIVER ELEC. COOP (BLAIR TRANS. CR.& L. PREST. CR.)			(\$70,699.80)	
18					
19	TOTAL ACCOUNT 454 (4110.4563.)	\$116,367.56	\$809,646.03	(\$29,437.34)	\$896,576.25
20					
21	FORFEITED DISCOUNTS 450 (4110.4500)	\$294,442.98	\$170,779.34	\$80,104.02	\$545,326.34
22					
23	LOAD CONTROL DISP. 456.6 (4110.4560)	\$2,229,531.91			\$2,229,531.91
24					
25	CONNECTION FEES 451.1 (4110.4521)	\$190,816.61	\$89,754.06	\$35,174.27	\$315,744.94
26	JOURNAL ENTRY ADJUSTMENT	\$0.00			\$0.00
27	RENT ACCOUNT 454 (4110.4540)	\$70,385.33	\$79,826.68	\$47,882.57	\$198,094.58
28	JOINT USE (4110.4540)	\$326,441.20			\$326,441.20
29					
30					
31	BIG STONE FUEL HANDLING FAC. 454.2			\$107,654.88	\$107,654.88
32	101 0 & 1011.4110.4540				
33	COYOTE RENTS 454.3 (1030.4110.4540)		\$3,000.00		\$3,000.00
34					
35	OTHER ELECTRIC REVENUES 456.2 (4110.4560)				\$3,666,937.48
36	ACTIVITY 0150 456.4 910 (4110.4560)				(\$1,077,270.79)
37	RUBBER GOODS TESTING 456.4 (4110.4520)				\$0.00
38	RUBBER GOODS SOLD 456.4 (4110.4560)				\$0.00
39	RDC LEASES/MTCE. AGRMTS 451.5 (4110.4520)				\$34,025.44
40	MISC. SERVICE REV. (4110.4520)				\$0.00
41	MISO TARIFF REVENUE				\$2,205,221.35
42	TRANS DEFICIENCY PYMT (4110.4563)				\$2,755,281.79
43	MAPP TRANS. REVENUE (4110.4564)				\$25,173.44
44	OTHER ELEC. REVENUE STATE ALLOCATION	\$3,424,215.92	\$3,424,215.92	\$760,936.87	
45	TOTAL OTHER ELECTRIC REVENUES	\$6,859,356.86	\$4,793,571.97	\$1,011,832.91	\$12,664,761.74
46					
47		\$6,859,356.86	\$4,793,571.97	\$1,011,832.91	\$12,664,761.74
48					
49			Forfeited Discounts	\$80,104.02	\$545,326.34
50			Misc. Serv. Revenues	\$35,174.27	\$349,770.38
51			Rent from Elec. Prop.	\$126,100.11	\$1,531,766.91
52			Other Elec. Rev.	\$770,454.51	\$10,237,898.11
53				<u>\$1,011,832.91</u>	<u>\$12,664,761.74</u>

Page 2 , Other Electric Revenue - Breakdown by States
(From Billing Report JE Prepared by Jill Bjorgum)
V:\Regulatory_Services\REPORTS\Jills Monthly\Other Electric Revenue 2007

Prepared by: kas
Reviewed by: jlb

Schedule of Interest Earned on Loan Pools and Economic Development Investments
Actual Year 2007

419.62-INTEREST REVENUES														
Line No.	State	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
ACCT 1560 (Old124): Loan Pool Interest														
1	MINNESOTA	5,434.37	10,421.44	996.08	3,845.49	5,386.02	837.38	6,800.89	2,999.18	3,533.40	3,979.72	5,909.42	3,319.36	53,462.75
2	NORTH DAKOTA	731.79	1,211.98	0.00	2,753.56	405.05	825.86	1,486.01	309.29	426.51	946.10	77.38	468.66	9,642.19
3	SOUTH DAKOTA	87.70	0.00	157.20	88.56	63.10	0.00	71.09	80.87	90.31	75.25	82.90	74.88	871.86
4	Total	6,253.86	11,633.42	1,153.28	6,687.61	5,854.17	1,663.24	8,357.99	3,389.34	4,050.22	5,001.07	6,069.70	3,862.90	63,976.80
5														63,977
419.6--INTEREST REVENUES, FED. & ST. EXEMPT														
7		(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	
8	Loan - Series A	599.37	593.87	531.47	582.57	558.19	0.00	0.00	0.00	1,762.11	1,054.89	567.46	544.20	6,794.13
9	Loan - Series B	681.81	681.81	681.81	681.81	669.14	0.00	0.00	0.00	681.81	681.81	681.81	681.81	6,123.62
10		-	-	-	-	-	-	-	-	-	-	-	-	-
11		-	-	-	-	-	-	-	-	-	-	-	-	-
12		-	-	-	-	-	-	-	-	-	-	-	-	-
13		-	-	-	-	-	-	-	-	-	-	-	-	-
14		-	-	-	-	-	-	-	-	-	-	-	-	-
15		-	-	-	-	-	-	-	-	-	-	-	-	-
16	Total	1,281.18	1,275.68	1,213.28	1,264.38	1,227.33	0.00	0.00	0.00	2,443.92	1,736.70	1,249.27	1,226.01	12,917.75
17														
Total Interest Earned 419.2 & 419.6														
18	Minnesota	6,715.55	11,697.12	2,209.36	5,109.87	6,613.35	837.38	6,800.89	2,999.18	5,977.32	5,716.42	7,158.69	4,545.37	66,380.50
19	North Dakota	731.79	1,211.98	0.00	2,753.56	405.05	825.86	1,486.01	309.29	426.51	946.10	77.38	468.66	9,642.19
20	South Dakota	87.70	0.00	157.20	88.56	63.10	0.00	71.09	80.87	90.31	75.25	82.90	74.88	871.86
21	Total	7,535.04	12,909.10	2,366.56	7,951.99	7,081.50	1,663.24	8,357.99	3,389.34	6,494.14	6,737.77	7,318.97	5,088.91	76,894.55
22														

Total to B-3 p. 1 of 4

(1) Information from File: Other Income Detail.xls supplied by General Accounting

Source: Workpaper Received from Acctg and Located in Misc Workpaper File

Prepared by: kas
Reviewed by: pjb

Rent from Electric Property - 2007

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Line No.	CO	BU	CC	ACCT	SUB	ACTY	PROJ	FERC1	FERC2	SumOfBalance
1	100	010	0000	4110	4540	0000	000000	40000	45400	40.80
2	100	010	1020	4110	4540	0000	000000	40000	45400	(1,175.00)
3	100	010	1100	4110	4540	0000	000000	40000	45400	38,324.10
4	100	010	1190	4110	4540	0000	000000	40000	45400	(17,667.41)
5	100	010	1200	4110	4540	0000	000000	40000	45400	(2,718.71)
6	100	010	1200	4110	4540	0000	101200	40000	45400	(31,126.14)
7	100	010	1290	4110	4540	0000	000000	40000	45400	21,999.17
8	100	010	1440	4110	4540	0000	000000	40000	45400	(250.00)
9	100	020	0000	4110	4540	0000	000000	40000	45400	(110,654.88)
10	100	030	0000	4110	4540	0000	000000	40000	45400	(9,472.68)
11	loan - Series	030	0010	4110	4540	0000	000000	40000	45400	(2,400.00)
12	loan - Series	030	0020	4110	4540	0000	000000	40000	45400	(9,394.56)
13		030	0060	4110	4540	0000	000000	40000	45400	(4,808.16)
14		030	0060	4110	4540	0000	100060	40000	45400	(400.00)
15		030	0080	4110	4540	0000	100080	40000	45400	(24.00)
16		030	0080	4110	4540	0000	100531	40000	45400	(13,500.00)
17		030	0110	4110	4540	0000	000000	40000	45400	(150.00)
18	100	030	0340	4110	4540	0000	000000	40000	45400	(133,052.31)
19	100	030	0870	4110	4540	0000	000000	40000	45400	(358,760.88)
20										(635,190.66)
21										
22										
23										
24										
25										
26										
27										
28						Total				(635,190.66)
29										
30	Rent From Electric Property					(642,576.67)	CC	CC		
31							>=0	<=870		
32										
33	Rent From Electric Property					(250.00)	CC			
34							1,440			
35										
36	Total Other Rent					(642,826.67)				
37										
38	Rent From Electric Property - Hootlake					(1,175.00)	CC			
39							1,020			
40										
41										
42	Rent From Electric Property - Big Stone					20,656.69	CC	CC		
43							>=1100	<=1190		
44										
45										
46	Rent From Electric Property - Coyote					(11,845.68)	CC	CC		
47							>=1200	<=1290		
48										
49	Total					(635,190.66)				

Source: FERC Database

(1) B-3, Page 5 of 6

Displaying Actual Balances for Period Dec-07
Account: 4110
Sub Account: 4540

Prepared by: kas
Reviewed by: pjb
Page 5 of 5

Line No.	(A)	(B)	(C)	(D)
	Code Combination	Account Description	Current Month	YTD Amount
1	100.010.0000.4110.4540.0000.000000.4540	.Other Electric Revenue..Rent From Elect Property..Rent from electric property	0	40.8
2	100.010.1020.4110.4540.0000.000000.4540	Electric Revenue..Rent From Elect Property..Rent from electric property	-525	-1,175.00
3	100.010.1100.4110.4540.0000.000000.4540	Administrative..Other Electric Revenue..Rent From Elect	-5,156.00	38,324.10
4	100.010.1190.4110.4540.0000.000000.4540	Share..Other Electric Revenue..Rent From Elect Property..Rent from	2,376.91	-17,667.41
5	100.010.1200.4110.4540.0000.000000.4540	Administrative..Other Electric Revenue..Rent From Elect Property..Rent from	0	-2,718.71
6	100.010.1200.4110.4540.0000.101200.4540	Administrative..Other Electric Revenue..Rent From Elect Property..Rent from	-17,331.16	-31,126.14
7	100.010.1290.4110.4540.0000.000000.4540	Share..Other Electric Revenue..Rent From Elect Property..Rent from electric property	11,265.26	21,999.17
8	100.010.1440.4110.4540.0000.000000.4540	Solway Combustion Turbine..Other Electric Revenue..Rent From Elect Property..Rent from	0	-250
9	100.020.0000.4110.4540.0000.000000.4540	.Other Electric Revenue..Rent From Elect Property..Rent from electric property	-9,221.24	-110,654.88
10	100.030.0000.4110.4540.0000.000000.4540	.Other Electric Revenue..Rent From Elect Property..Rent from electric property	-786.89	-9,472.68
11	100.030.0010.4110.4540.0000.000000.4540	Service Center..Other Electric Revenue..Rent From Elect Property..Rent from elec	0	-2,400.00
12	100.030.0020.4110.4540.0000.000000.4540	Service Center..Other Electric Revenue..Rent From Elect Property..Rent from elec	-782.88	-9,394.56
13	Loan - Series A	Wanpeton Customer Service Center..Other Electric Revenue..Rent From Elect Property..Rent from	-400.68	-4,808.16
14	Loan - Series B	Service Center..Other Electric Revenue..Rent From Elect Property..Rent from	0	-400
15		Regency Customer Service Center..Other Electric Revenue..Rent From Elect Property..Rent from electric pr	0	-24
16		Service Center..Other Electric Revenue..Rent From Elect Property..Rent from electric pr	-1,125.00	-13,500.00
17		Chowton Customer Service Center..Other Electric Revenue..Rent From Elect Property..Rent from	0	-150
18		Telecommunications Services..Other Electric Revenue..Rent From Elect Property..Rent from	-18,716.06	-133,052.31
19		Electric Revenue..Rent	2,221.22	-358,760.88
20		Totals	(\$38,181.52)	(\$635,190.66)

Source: GL Fire Report

(A) (B) (C) (D) (E) (F) (G) (H)

11	(1) B-4 Page 3 Of 12 and to Regulatory Economics Purchase Power worksheets. See proof below	
12	(2) B-4, Page 2 Of 12 and to Regulatory Economics Purchase Power worksheets.	
13	(3) Participation Power Energy Charge Classified Base Energy Per Allocation Manual	
14	(4) Not Used	
15	(5) No purchase of peaking power; no longer used per System Operations.	
16	(6) All expense except participation power & peak power are classified as base energy per Alloc. Manual	
17	(7) Total Purchased Power - See proof below	
18	(8) Not Used	
19	(9) no longer used	
20	(10) Not Used	
21	(11) reconciles to FERC 12/07 F/S, Page 5	
22	Purchased Power - System Use	74,694,689
23	Control Area Exchange - net (FERC Form 1 page 327)	1,532,363
24		
25	Difference	76,227,052
26	(12) FERC Form #1, page 327 - See proof below	-
27	(13) Ties To Purchase Power Print Outs 12-07 & To Ferc Form #1, Page 327 total energy plus net control area exchange.	

Prepared By: kas
Reviewed By: pjb

Otter Tail Power Company
Purchased Power
Actual Year Ending December 31, 2007

(14) Ties To Purchase Power spreadsheet 12-07 (totals start in row AB674 of purchase power worksheet) - See proof below

	(A)	(B)	(C)	(D)
Line No.	PROOF OF DEMAND AND RELATED CHARGES (plus reconciliation to FERC Form 1 page 327)			
1	Demand Charges column (j) p. 327 FERC Form 1		Other Charges column (l) p.327 FERC Form 1	
2	All Other Demand		Other Energy Related Charges	
3	GRE	253,750	Schedule and Dispatch charges	
4	MHEB 50 MW 12 months	1,602,800	Cargill Power Markets	2,592
5	MEC	-	OPPD	1,315
6	MP	-	MISO Transmission	178,656
7	Minnkota Power	-	MAPP Transmission	272,582
8	MRES	-	WAPA	23,552
9	NSP/Xcel	149,000	Total Schedule and Dispatch	478,697
10	Wisconsin Public Power Inc.	207,500	Other Demand Related Charges	
11	NorthWestern Energy - NLE	143,795	Load Following Charge	
12	SRE	-	WAPA	20,022
13	Red Lake Rural Electric Co-op	14,007	Total Load Following (a)	20,022
14	City of Perham	31,052	BEC Nomination chg (demand) (a)	124,967
15	Generator # 1	35,832	MHEB	(837,247)
16	Generator # 2	36,000	Energy Related Charges	(358,550)
17	Generator # 3	35,460	Demand Related Charges	144,989
18	Generator # 4	17,944	Total Other charges	(213,561)
19	Generator # 5	104,710	FERC form 1 page 327 total	(213,561)
20	Generator # 6	20,520	Unidentified difference	-
21	Generator # 7	-	@ Difference due to Rounding	@
22	City of Detroit Lakes	1,110		
23	plus WAPA load following	20,022		
24	Total All Other Demand	2,673,502		
25	Participation Power Demand			
26	Beltrami Electric Cooperative total			
27	Nodak	1,085,491		
28	PKM	39,814		
29	plus nomination charge	39,978		
30	Total Participation Power Demand	1,290,250		
31	(1) Total Demand	3,963,752		
32	(7) & (12) Total Demand less - sum of (a):	3,818,763		
33	FERC form 1 page 327 total	3,818,763		
34	difference	-		

Prepared By: kas
Reviewed By: pjb

Otter Tail Power Company
Purchase Power-Participation Power
Actual Year Ending December 31, 2007

	(A)	(B)	(C)	(D)
Line No.	Shared Customers	Base Demand	Peak Demand	Total Demand Charges
		(1)	(2)	(2)
1	<u>Beltrami:</u>			
2	Station 1	\$ 280,077.10	0	\$ 280,077
3	Station 2	\$ 316,585.49	0	316,585
4	Station 3	\$ 94,925.04	0	94,925
5	Station 4	\$ 314,400.64	0	314,401
6	Station 5	\$ 29,523.13	0	29,523
7	Station 6	\$ 174,945.86	0	174,946
8	NODAK	39,814	0	39,814
9	PKM	39,978	0	39,978
10	Other	0	0	0
11				
12		\$ 1,290,249	0	\$ 1,290,249
13				

- (1) Total Demand Less Peak Demand
(2) B-4 Page 3 OF 12

Note: All Purchased Power Expenses (A/C 555) Except Those Labeled "Participation" Or "Peaking Power" Are Classified As Base Energy Per Otter Tail Power's Cost Allocation Procedure Manual. There Was Not Any Peaking Power In The Actual Year Ending Dec 31, 1992. There Was Participation Power (Shared Customers & NSE) And Everything Else Is Considered "All Other".

Otter Tail Power Company
Purchased Power - Shared Customers
Actual Year Ending December 31, 2007

Prepared By: kas
Reviewed By: pjb

Line No.	(A) CUSTOMERS	(B) Peaking Rate	(C) Demand	(D) Number of Months	(E) Peak Demand (10)
		(1)			
1	Beltrami:				
2	Station 1	\$0	2.0 (2)	12 (2)	0
3	Station 2	0	3.2 (3)	12 (3)	0
4	Station 3	0	1.1 (11)	12 (11)	0
5	Station 4	0	5.6 (4)	12 (4)	0
6	Station 5	0	0.3 (5)	12 (5)	0
7	Station 6	0	1.3 (6)	12 (6)	0
8	NODAK	0	0.5 (7)	12 (7)	0
9	PKM	0	0.5 (8)	12 (8)	0
10	Other	0	0.0 (9)	12 (9)	0
11					
12		TOTAL PEAK DEMAND			\$0

Line No.		Demand Charge	Energy Charge	Total Charge	Check Totals From pp 4-12	Difference
14						
15						
16						
17	Beltrami:					
18	Station 1 (2)	\$ 280,077	\$ 720,075	\$ 1,000,152	1,000,151.75	-
19	Station 2 (3)	316,585	886,854	1,203,440	\$1,203,439.80	-
20	Station 3 (11)	94,925	238,445	333,370	\$333,370.27	-
21	Station 4 (4)	314,401	827,585	1,141,985	\$1,141,985.47	-
22	Station 5 (5)	29,523	100,687	130,210	\$130,210.46	-
23	Station 6 (6)	174,946	563,298	738,244	\$738,244.22	-
24	NODAK (7)	39,814	165,572	205,386	\$205,385.97	-
25	PKM (8)	39,978	132,907	172,885	\$172,884.97	-
26	Other (9)	0	0	0		
27						
28	Totals	\$ 1,290,249	\$ 3,635,424	\$ 4,925,673	\$ 4,925,673	-

(1) Current Mapp Schedule H-Peaking Rate has been eliminated.

(2) W/P B-4 Page 4 Of 12

(3) W/P B-4 Page 5 Of 12

(4) W/P B-4 Page 6 Of 12

(5) W/P B-4 Page 7 Of 12

(6) W/P B-4 Page 8 Of 12

(7) W/P B-4 Page 9 Of 12

(8) W/P B-4 Page 10 Of 12

(9) W/P B-4 Page 11 Of 12

(10) Calculation Based On Formula In OTP'S Cost Allocation Procedure Manual (Page 12) As Follows:

Mapp Schedule H (Peaking) Rate X Demand (Mw) X Number Of Months

(11) W/P B-4 Page 12 Of 12

Prepared By: kas
Reviewed By: pjb

BELTRAMI ELECTRIC COOPERATIVE
Station 1

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
Line No.	2007		METER READING	DIFF.	KW	KWH	DEMAND CHARGE	ENERGY CHARGE	MN PROPERTY TAX REFUND	COE	INTERIM RATE ADJUSTMENT	NOMINATION CHARGE	TOTAL
1	JAN.	ON-PEAK	6429682	148034.4	2000.0	1,828,473	\$17,080.00	\$45,289.87	(\$242.74)	\$21,770.10	\$0.00	\$5,798.80	\$89,696.03
2			6281647.6										
3		OFF-PEAK	4269547.4	217660.2									
4			4051887.2										
5	FEB.	ON-PEAK	6558664.2	128982.2	2000.0	1,674,903	\$17,080.00	\$41,146.85	(\$239.78)	\$24,813.44	\$0.00	\$5,798.80	\$88,599.31
6			6429682										
7		OFF-PEAK	4475545.8	205998.4									
8			4269547.4										
9	MAR.	ON-PEAK	6703395.4	144731.2	2000.0	1,637,140	\$17,080.00	\$41,175.31	(\$233.84)	\$22,795.45	\$0.00	\$5,586.05	\$86,402.97
10			6558664.2										
11		OFF-PEAK	4658242.6	182696.8									
12			4475545.8										
13	APR.	ON-PEAK	6847036.2	143640.8	2000.0	1,661,843	\$17,080.00	\$41,628.81	(\$244.22)	\$24,487.79	\$0.00	\$7,288.05	\$90,240.43
14			6703395.4										
15		OFF-PEAK	4846970.3	188727.7									
16			4658242.6										
17	MAY	ON-PEAK	6963083.6	116047.4	2000.0	1,507,158	\$17,080.00	\$37,024.99	(\$231.42)	\$25,415.97	\$0.00	\$6,224.30	\$85,513.84
18			6847036.2										
19		OFF-PEAK	5032354.4	185384.1									
20			4846970.3										
21	JUNE	ON-PEAK	7070970.8	107887.2	2000.0	1,382,879	\$17,080.00	\$34,044.17	(\$197.91)	\$14,913.97	\$0.00	\$7,288.05	\$73,128.29
22			6963083.6										
23		OFF-PEAK	5201043	168688.6									
24			5032354.4										
25	JULY	ON-PEAK	7188643.2	117672.4	2000.0	1,674,283	\$17,080.00	\$40,554.42	(\$209.83)	\$12,181.51	\$0.00	\$7,926.30	\$77,532.40
26			7070970.8										
27		OFF-PEAK	5418227.2	217184.2									
28			5201043										
29	AUG.	ON-PEAK	7348151.4	159508.2	2000.0	1,836,774	\$17,080.00	\$46,049.08	(\$234.61)	\$16,718.84	\$0.00	\$7,075.30	\$86,688.61
30			7188643.2										
31		OFF-PEAK	5626073.7	207846.5									
32			5418227.2										
33	SEPT.	ON-PEAK	7461720.4	113569	2000.0	1,647,495	\$17,080.00	\$39,791.73	(\$195.15)	\$9,632.41	\$0.00	\$5,798.80	\$72,107.79
34			7348151.4										
35		OFF-PEAK	5842003.7	215930									
36			5626073.7										
37	OCT.	ON-PEAK	7597764.9	136044.5	2000.0	1,839,473	\$17,080.00	\$44,902.21	(\$205.70)	\$8,219.55	\$0.00	\$6,011.55	\$76,007.61
38			7461720.4										
39		OFF-PEAK	6073853.7	231850									
40			5842003.7										
41	NOV.	ON-PEAK	7726000.5	128235.6	2000.0	1,608,638	\$17,080.00	\$55,522.91	(\$183.84)	(\$5,633.89)	\$283.54	\$6,011.55	\$73,080.27
42			7597764.9										
43		OFF-PEAK	6267345.6	193491.9									
44			6073853.7										
45	DEC.	ON-PEAK	7871376.5	145376	2000.0	1,854,931	\$17,080.00	\$63,896.04	\$0.00	\$11,254.66	\$4,613.95	\$4,309.55	\$101,154.20
46			7726000.5										
47		OFF-PEAK	6492955.7	225610.1									
48			6267345.6										
49	TOTAL				24,000	20,153,987	204,960.00	531,026.39	(2,419.04)	186,569.80	4,897.49	75,117.10	1,000,151.75
50													1,000,151.75
51													
52													
53	Monthly Average Kw = Total Demand / 12												
54	2,000.00												
55	Total Energy = Energy Charge - PPT + COE+INT RATE ADJ												
56	720,074.65												
57	USE= 2.00												

Source: Shared customer billings.
Computer File:V:\regulatory_services\customers\shared and gen loads

Beltrami Electric Cooperative
Station 2

Prepared By: kas
Reviewed By: pjb

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No.	2007	Meter Reading	Diff.	KW	KWH	Demand Charge	Energy Charge	MN PROPERTY TAX	COE	INTERIM RATE ADJUSTMENT	Total
1	JAN.	5946	1718	3265.2	2,061,600	\$29,202.81	\$60,456.15	(\$316.05)	\$28,318.14	\$0.00	\$117,661.05
2		4228									
3	FEB.	7887	1941	3264.0	2,329,200	\$29,463.44	\$67,816.42	(\$335.11)	\$27,810.16	\$0.00	\$124,754.91
4		5946									
5	MAR.	9401	1514	3249.6	1,816,800	\$29,463.44	\$53,792.03	(\$295.42)	\$27,019.16	\$0.00	\$109,979.21
6		7887									
7	APR.	11010	1609	3232.8	1,930,800	\$29,463.44	\$56,912.21	(\$303.64)	\$26,967.47	\$0.00	\$113,039.48
8		9401									
9	MAY	12598	1588	3234.0	1,905,600	\$28,274.99	\$56,058.12	(\$301.32)	\$28,144.56	\$0.00	\$112,176.35
10		11010									
11	JUNE	14415	1817	3136.8	2,180,400	\$28,274.99	\$63,579.40	(\$344.67)	\$36,803.54	\$0.00	\$128,313.25
12		12598									
13	JULY	15843	1428	3097.2	1,713,600	\$28,274.99	\$50,803.08	(\$261.49)	\$18,530.93	\$0.00	\$97,347.51
14		14415									
15	AUG.	17570	1727	3067.2	2,072,400	\$26,747.72	\$60,412.21	(\$274.01)	\$15,123.14	\$0.00	\$102,009.06
16		15843									
17	SEPT.	19110	1540	3080.4	1,848,000	\$21,471.28	\$53,540.65	(\$246.09)	\$16,853.86	\$0.00	\$91,619.70
18		17570						August adj.			
19	OCT.	20344	1234	3139.2	1,480,800	\$21,879.94	\$43,546.90	(\$198.65)	\$8,726.02	\$0.00	\$73,954.21
20		19110									
21	NOV.	21541	1197	3156.0	1,436,400	\$21,996.70	\$42,347.82	(\$189.80)	\$6,502.83	\$0.00	\$70,657.55
22		20344									
23	DEC.	22382	841	3166.8	1,009,200	\$22,071.76	\$40,216.62	(\$13.14)	(\$3,437.23)	\$3,089.51	\$61,927.52
24		21541									
25											
26											
27											
28	TOTAL			38,089.20	21,784,800.00	\$316,585.49	\$649,481.61	(\$3,079.38)	\$237,362.57	\$3,089.51	\$1,203,439.80
29											\$1,203,439.80
30											
31											
32	Monthly Average Kw = Total Demand / 12						3,174.10				
33	Total Energy = Energy Charge - PPT + COE+INT RATE ADJ.						\$886,854.31	USE =			
34											
35											

Source: Shared customer billings.
Computer File:V:\regsrv\customers\shared and gen loads

Beltrami Electric Cooperative
Station 3

Prepared By: kas
Reviewed By: pjb

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
Line No.	2007		Meter Reading	Diff	KW	KWH	Demand Charge	Energy Charge	MN PROPERTY TAX CREDIT	INTERIM RATE ADJUSTMENT	COE	Total
1	JAN.	ON-PEAK	123089	1752	5752.0	2,033,000	\$25,887.20	\$51,891.00	(\$283.03)	\$0.00	\$27,845.71	\$105,340.88
2			121337									
3		OFF-PEAK	208137	2314								
4			205823									
5	FEB.	ON-PEAK	124845	1756	5983.5	1,955,000	\$26,536.80	\$50,274.00	(\$268.27)	\$0.00	\$23,306.18	\$99,848.71
6			123089									
7		OFF-PEAK	210291	2154								
8			208137									
9	MAR.	ON-PEAK	126530	1685	6066.0	1,881,000	\$27,208.80	\$48,347.25	(\$277.20)	\$0.00	\$27,894.32	\$103,173.17
10			124845									
11		OFF-PEAK	212368	2077								
12			210291									
13	APR.	ON-PEAK	128155	1625	5763.5	1,835,000	\$25,954.40	\$47,066.25	(\$264.17)	\$0.00	\$25,561.61	\$98,318.09
14			126530									
15		OFF-PEAK	214413	2045								
16			212368									
17	MAY	ON-PEAK	129901	1746	5810.5	2,092,000	\$25,999.20	\$53,098.50	(\$294.47)	\$0.00	\$30,796.63	\$109,599.86
18			128155									
19		OFF-PEAK	216851	2438								
20			214413									
21	JUNE	ON-PEAK	131253	1352	2918.5	1,754,000	\$26,209.76	\$43,932.00	(\$267.22)	\$0.00	\$29,578.29	\$99,452.83
22			129901									
23		OFF-PEAK	219007	2156								
24			216851									
25	JULY	ON-PEAK	132910	1657	5739.5	2,100,500	\$25,654.24	\$52,809.75	(\$270.74)	\$0.00	\$22,576.55	\$100,769.80
26			131253									
27		OFF-PEAK	221551	2544								
28			219007									
29	AUG.	ON-PEAK	134367	1457	5751.5	1,794,500	\$25,949.92	\$45,333.75	(\$226.03)	\$0.00	\$13,063.98	\$84,121.62
30			132910									
31		OFF-PEAK	223683	2132								
32			221551									
33	SEPT.	ON-PEAK	135965	1598	5714.5	1,957,000	\$25,725.92	\$49,486.50	(\$249.28)	\$0.00	\$17,816.47	\$92,779.61
34			134367									
35		OFF-PEAK	225999	2316								
36			223683									
37	OCT.	ON-PEAK	137231	1266	5717.0	1,743,500	\$25,591.52	\$43,260.00	(\$211.88)	\$0.00	\$10,212.89	\$78,852.53
38			135965									
39		OFF-PEAK	228220	2221								
40			225999									
41	NOV.	ON-PEAK	138941	1710	5926.0	1,982,000	\$26,819.04	\$50,599.50	(\$231.28)	\$0.00	\$8,887.80	\$86,075.06
42			137231									
43		OFF-PEAK	230474	2254								
44			228220									
45	DEC.	ON-PEAK	140430	1489	6031.5	1,750,000	\$26,863.84	\$61,734.75	(\$160.08)	\$1,320.51	(\$6,105.71)	\$83,653.31
46			138941									
47		OFF-PEAK	232485	2011								
48			230474									
49												
50												
51												
52	TOTAL				67,174	22,877,500	\$314,400.64	\$597,833.25	(\$3,003.65)	\$1,320.51	\$231,434.72	\$1,141,985.47
53												\$1,141,985.47
54												
55												
56												
57												
58												
59												
60												
61												

Source: Shared customer billings.
Computer File:V:\regsr\customers\shared and gen loads

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
Line No.			Meter Reading	Diff.	KW	KWH	Demand Charge	Energy Charge	MN PROPERTY TAX CREDIT	COE	INTERIM RATE ADJUSTMENT	NOMINATION CHARGE	Total
1	JAN.	ON-PEAK	2975278.7	24413.5	250.0	291,669	\$2,187.50	\$7,265.42	(\$35.60)	\$3,464.04	\$0.00	\$272.76	\$13,154.12
2			2950865.2										
3		OFF-PEAK	4238842.9	33920.2									
4			4204922.7										
5	FEB.	ON-PEAK	3001640.8	26362.1	250.0	276,642	\$2,187.50	\$7,055.34	(\$36.73)	\$4,090.47	\$0.00	\$272.76	\$13,569.34
6			2975278.7										
7		OFF-PEAK	4267809.2	28966.3									
8			4238842.9										
9	MAR.	ON-PEAK	3021994.3	20353.5	250.0	235,499	\$2,187.50	\$5,899.10	(\$31.40)	\$3,272.89	\$0.00	\$272.76	\$11,600.85
10			3001640.8										
11		OFF-PEAK	4294555.4	26746.2									
12			4267809.2										
13	APR.	ON-PEAK	3039055.3	17061	250.0	203,579	\$2,187.50	\$5,072.17	(\$28.42)	\$2,995.67	\$0.00	\$272.76	\$10,499.68
14			3021994.3										
15		OFF-PEAK	4318210.3	23654.9									
16			4294555.4										
17	MAY	ON-PEAK	3050293.6	11238.3	250.0	136,856	\$2,187.50	\$3,397.96	(\$22.05)	\$2,310.72	\$0.00	\$272.77	\$8,146.90
18			3039055.3										
19		OFF-PEAK	4334343.2	16132.9									
20			4318210.3										
21	JUNE	ON-PEAK	3065887.3	15593.7	250.0	184,219	\$2,187.50	\$4,597.73	(\$24.40)	\$1,981.33	\$0.00	\$272.76	\$9,014.92
22			3050293.6										
23		OFF-PEAK	4355593.3	21250.1									
24			4334343.2										
25	JULY	ON-PEAK	3084528.1	18640.8	250.0	203,734	\$2,187.50	\$5,156.35	(\$24.55)	\$1,479.59	\$0.00	\$272.76	\$9,071.65
26			3065887.3										
27		OFF-PEAK	4377699.3	22106									
28			4355593.3										
29	AUG.	ON-PEAK	3100499.9	15971.8	250.0	200,991	\$2,187.50	\$4,962.96	(\$24.97)	\$1,827.53	\$0.00	\$272.76	\$9,225.78
30			3084528.1										
31		OFF-PEAK	4401925.7	24226.4									
32			4377699.3										
33	SEPT.	ON-PEAK	3117014	16514.1	250.0	240,473	\$2,187.50	\$5,804.94	(\$26.09)	\$1,399.36	\$0.00	\$272.76	\$9,638.47
34			3100499.9										
35		OFF-PEAK	4433506.3	31580.6									
36			4401925.7										
37	OCT.	ON-PEAK	3140474.9	23460.9	250.0	283,892	\$2,187.50	\$7,056.21	(\$29.09)	\$1,261.22	\$0.00	\$272.76	\$10,748.60
38			3117014										
39		OFF-PEAK	4466823.8	33317.5									
40			4433506.3										
41	NOV.	ON-PEAK											

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Beltrami Electric Cooperative
Station 5

Prepared By: kas
Reviewed By: pjb

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
Line No.	2007		Meter Reading	Diff.	KW	KWH	Demand Charge	Energy Charge	MN PROPERTY TAX CREDIT	COE	INTERIM RATE ADJUSTMENT	NOMINATION CHARGE	Total
1													
2	JAN.	ON-PEAK	6044842.4	111171.5	1250.0	1,376,952	\$10,697.50	\$34,090.27	(\$177.38)	\$16,379.27	\$0.00	\$4,555.03	\$65,544.69
3			5933670.9										
4		OFF-PEAK	3169686.7	164218.9									
5			3005467.8										
6	FEB.	ON-PEAK	6139658	94815.6	1250.0	1,164,370	\$10,697.50	\$28,868.58	(\$165.64)	\$17,247.05	\$0.00	\$4,555.03	\$61,202.52
7			6044842.4										
8		OFF-PEAK	3307745	138058.3									
9			3169686.7										
10	MAR.	ON-PEAK	6278850.9	139192.9	1250.0	1,602,106	\$10,697.50	\$40,169.04	(\$210.23)	\$22,256.33	\$0.00	\$4,767.78	\$77,680.42
11			6139658										
12		OFF-PEAK	3488973.3	181228.3									
13			3307745										
14	APR.	ON-PEAK	6414230.5	135379.6	1250.0	1,591,104	\$10,697.50	\$39,746.78	(\$208.09)	\$23,374.44	\$0.00	\$3,278.53	\$76,889.16
15			6278850.9										
16		OFF-PEAK	3671814.4	182841.1									
17			3488973.3										
18	MAY	ON-PEAK	6487125.6	72895.1	1250.0	880,811	\$10,697.50	\$21,898.21	(\$131.72)	\$14,843.83	\$0.00	\$1,363.78	\$48,671.60
19			6414230.5										
20		OFF-PEAK	3775081.5	103267.1									
21			3671814.4										
22	JUNE	ON-PEAK	6551430.8	64305.2	1250.0	852,293	\$10,697.50	\$20,869.90	(\$115.37)	\$9,173.51	\$0.00	\$2,002.03	\$42,627.58
23			6487125.6										
24		OFF-PEAK	3881234.9	106153.4									
25			3775081.5										
26	JULY	ON-PEAK	6654264	102833.2	1250.0	1,286,493	\$10,697.50	\$31,797.70	(\$148.14)	\$9,323.97	\$0.00	\$3,065.78	\$54,736.81
27			6551430.8										
28		OFF-PEAK	4035700.2	154465.3									
29			3881234.9										
30	AUG.	ON-PEAK	6771012.6	116748.6	1250.0	1,447,592	\$10,697.50	\$35,832.73	(\$167.57)	\$13,128.61	\$0.00	\$2,427.53	\$61,918.80
31			6654264										
32		OFF-PEAK	4208470	172769.8									
33			4035700.2										
34	SEPT.	ON-PEAK	6874774.6	103762	1250.0	1,429,757	\$10,697.50	\$34,799.37	(\$157.56)	\$8,326.84	\$0.00	\$4,555.03	\$58,221.18
35			6771012.6										
36		OFF-PEAK	4390659.4	182189.4									
37			4208470										
38	OCT.	ON-PEAK	6975990.4	101215.8	1250.0	1,304,259	\$10,697.50	\$32,081.12	(\$144.05)	\$5,823.01	\$0.00	\$4,767.78	\$53,225.36
39			6874774.6										
40		OFF-PEAK	4550295.3	159635.9									
41			4390659.4										
42	NOV.	ON-PEAK	7107930.9	131940.5	1250.0	1,589,466	\$10,697.50	\$55,129.35	(\$163.67)	(\$5,619.87)	\$254.61	\$4,767.78	\$65,065.70
43			6975990.4										
44		OFF-PEAK	4736248	185952.7									
45			4550295.3										
46	DEC.	ON-PEAK	7197678.5	89747.6	1250.0	1,297,832	\$10,697.50	\$44,092.55	\$0.00	\$7,886.42	\$3,314.16	\$6,469.78	\$72,460.41
47			7107930.9										
48		OFF-PEAK	4906066.8	169818.8									
49			4736248										
50	TOTAL				15,000.00	15,823,033.00	\$128,370.00	\$419,375.60	(\$1,789.42)	\$142,143.41	\$3,568.77	\$46,575.86	\$738,244.22
51													\$738,244.22
52													
53													
54													
55													
56													
57													
58													
			Monthly Average Kw = Total Demand / 12										
			Total Energy = Energy Charge - PPT + COE+INT RATE ADJ										
							1,250.00			USE =			1.25
							\$563,298.36						

Source: Shared customer billings.
Computer File:V:\regsrvc\customers\shared and gen loads

NODAK
2007

Prepared By: kas
Reviewed By: pjb

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line No.	2007 Month	Reading	Difference	Demand	Energy = Difference X 2400 / 2	Demand Charge	Energy Charge	COE Adjustment	Total Bill
1	JAN	3068	234	482.4	280,800	\$3,216.92	\$9,715.89	\$3,875.04	\$16,807.85
2		2834							
3	FEB	3294	226	490.8	271,200	\$3,271.61	\$9,459.80	\$3,769.68	\$16,501.09
4		3068							
5	MAR	3554	260	498.0	312,000	\$3,318.48	\$10,679.29	\$5,647.20	\$19,644.97
6		3294							
7	APR	3792	238	490.8	285,600	\$3,271.61	\$9,882.44	\$5,654.88	\$18,808.93
8		3554							
9	MAY	4045	253	501.6	303,600	\$3,341.92	\$10,443.75	\$6,557.76	\$20,343.43
10		3792							
11	JUN	4298	253	501.6	303,600	\$3,341.92	\$10,443.75	\$6,041.64	\$19,827.31
12		4045							
13	JUL	4534	236	504.0	283,200	\$3,357.54	\$9,852.35	\$4,644.48	\$17,854.37
14		4298							
15	AUG	4768	234	495.6	280,800	\$3,302.86	\$9,756.23	\$2,948.40	\$16,007.49
16		4534							
17	SEP	4998	230	495.6	276,000	\$3,302.86	\$9,615.35	\$717.60	\$13,635.81
18		4768							
19	OCT	5237	239	507.6	286,800	\$3,380.98	\$9,969.01	\$745.68	\$14,095.67
20		4998							
21	NOV	5466	229	511.2	274,800	\$3,404.41	\$9,627.81	\$989.28	\$14,021.50
22		5237							
23	DEC	5709	243	495.6	291,600	\$3,302.86	\$10,073.21	\$4,461.48	\$17,837.55
24		5466							
25									
26									
27									
28									
29									
30									
31	TOTAL			5974.8	3,450,000	\$39,813.97	\$119,518.88	\$46,053.12	\$205,385.97
32									\$205,385.97

Monthly Average Kw = Total Demand / 12	497.9	Use =	0.5
		Total Energy	\$165,572.00
* These Totals Are Based On The Standard Minnkota Rate + 20%			

Source: Shared customer billings.
Computer File: V:\regsrv\customers\shared and gen loads

Prepared By: kas
Reviewed By: pjb

PKM Electric Cooperative, Inc.
PKM

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No.	2007	Meter Reading	Diff.	KW	KWH	Demand Charge	Energy Charge	MN PROPERTY TAX CREDIT	COE	INTERIM RATE ADJUSTMENT	Total
1	JAN.	1159282	557656	453.6	278,828	\$3,215.02	\$8,067.52	(\$39.13)	\$3,326.42	\$0.00	\$14,569.83
2		601626									
3	FEB.	667748	508466	465.6	254,233	\$3,298.42	\$7,405.89	(\$38.78)	\$3,773.82	\$0.00	\$14,439.35
4		159282									
5	MAR.	1230733	562985	474.7	281,493	\$3,361.67	\$8,160.73	(\$41.38)	\$3,923.58	\$0.00	\$15,404.60
6		667748									
7	APR.	780835	550102	469.0	275,051	\$3,321.71	\$7,978.91	(\$41.14)	\$4,055.79	\$0.00	\$15,315.27
8		230733									
9	MAY	1332545	551710	444.5	275,855	\$3,151.78	\$7,977.41	(\$42.28)	\$4,652.55	\$0.00	\$15,739.45
10		780835									
11	JUNE	1875506	542961	447.9	271,481	\$3,175.06	\$7,860.90	(\$37.40)	\$2,924.61	\$0.00	\$13,923.16
12		1332545									
13	JULY	1435870	560364	476.2	280,182	\$3,371.75	\$8,126.26	(\$36.28)	\$2,042.45	\$0.00	\$13,504.18
14		875506									
15	AUG.	1012345	576475	449.8	288,238	\$3,188.27	\$8,321.36	(\$37.87)	\$2,627.32	\$0.00	\$14,099.08
16		435870									
17	SEPT.	541865	529520	467.5	264,760	\$3,311.63	\$7,695.84	(\$33.65)	\$1,554.99	\$0.00	\$12,528.81
18		12345									
19	OCT.	1098517	556652	491.1	278,326	\$3,475.30	\$8,089.78	(\$34.34)	\$1,253.26	\$0.00	\$12,784.00
20		541865									
21	NOV.	637867	539350	506.4	269,675	\$3,581.98	\$10,513.27	(\$34.03)	(\$937.60)	\$26.78	\$13,150.40
22		98517									
23	DEC.	1220964	583097	498.3	291,549	\$3,525.34	\$11,318.69	\$0.00	\$1,779.75	\$803.06	\$17,426.84
24		637867									
25											
26	TOTAL			5,644.3	3,309,669.00	\$39,977.93	\$101,516.55	(\$416.28)	\$30,976.94	\$829.84	\$172,884.97
27											172,884.97
28											
29											
30	Monthly Average Kw = Total Demand / 12 470.4 Use= 0.5										
31											
32	Total Energy = Energy Charge - PPT + COE+INT RATE AD: \$132,907.05										
33											

Source: Shared customer billings.
Computer File:V:\regsr\customers\shared and gen loads

Prepared By: kas
Reviewed By: pjb

Other
Enderlin, ND
2007

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.		On-Peak KWH	Total KWH	Energy	KWH	Energy Charge	Total
1				TOTAL	0	\$0.00	\$0.00
2	TOTAL						\$0.00
3						Total Energy	\$0.00

Source:Purchase Power Report -Regulatory Services
Note: No activity for a number of years.

Beltrami Electric Cooperative
Other

Prepared By: kas
Reviewed By: pjb

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No.	2007	Meter Reading	Diff.	KW	KWH	Demand Charge	Energy Charge	MN PROPERTY TAX CREDIT	INTERIM RATE ADJUSTMENT	COE	Total
1	JAN.	1254	435	1134.0	522,000	\$7,950.75	\$15,378.10	(\$81.71)	\$0.00	\$7,174.90	\$30,422.04
2		819									
3	FEB.	1740	486	1156.1	583,200	\$8,097.40	\$17,073.43	(\$86.10)	\$0.00	\$6,969.39	\$32,054.12
4		1254									
5	MAR.	2111	371	1106.4	445,200	\$7,772.83	\$13,251.48	(\$74.07)	\$0.00	\$6,625.62	\$27,575.86
6		1740									
7	APR.	2530	419	1155.6	502,800	\$8,125.20	\$14,876.73	(\$80.45)	\$0.00	\$7,026.42	\$29,947.90
8		2111									
9	MAY	2909	379	1099.4	454,800	\$7,703.33	\$13,504.62	(\$74.83)	\$0.00	\$6,725.23	\$27,858.35
10		2530									
11	JUNE	3335	426	1093.4	511,200	\$7,661.63	\$15,042.52	(\$83.96)	\$0.00	\$8,637.44	\$31,257.63
12		2909									
13	JULY	3684	349	1088.4	418,800	\$7,665.11	\$12,514.01	(\$66.21)	\$0.00	\$4,535.31	\$24,648.22
14		3335									
15	AUG.	4100	416	1087.2	499,200	\$7,660.24	\$14,713.89	(\$69.73)	\$0.00	\$3,653.21	\$25,957.61
16		3684									
17	SEPT.	4504	404	1089.3	484,800	\$7,633.14	\$14,316.01	(\$70.69)	\$0.00	\$4,438.44	\$26,316.90
18		4100									
19	OCT.	4868	364	1099.2	436,800	\$7,701.94	\$13,011.77	(\$62.41)	\$0.00	\$2,584.57	\$23,235.87
20		4504									
21	NOV.	5326	458	1124.7	549,600	\$8,277.81	\$16,454.24	(\$72.93)	\$0.00	\$2,488.98	\$27,148.10
22		4868									
23	DEC.	5709	383	1177.2	459,600	\$8,675.66	\$18,503.87	(\$5.72)	\$1,348.11	(\$1,574.25)	\$26,947.67
24		5326									
25											
26											
27											
28											
29											
30											
31	TOTAL			13,410.9	5,868,000	\$94,925.04	\$178,640.67	(\$828.81)	\$1,348.11	\$59,285.26	\$333,370.27
32											\$333,370.27

Monthly Average KW = Total Demand / 12

1117.6

Use=

1.1

Total Energy = Energy Charge - PPT + COE+INT RATE ADJ

\$238,445.23

Source: Shared customer billings.

Computer File:V:\regsrv\customers\shared and gen loads

Prepared By: kas
Reviewed By: pjb

Otter Tail Power Company
Regulatory Commission Expense
Actual 12 months ending 12/31/07

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.			Minnesota	North Dakota	South Dakota	FERC	Total
1							
2							
3	Filing Fees	(1)		650			650
4							
5	PBR	(1)					0
6							
7	Assessment	(1)	296,641	741	34,475	142,211	474,069
8							
9							
10							
11							
12							
13							
14							
15	Miscellaneous	(1)	1,111,677	95,312	7,388	63,032	1,277,409
16							
17	Total		1,408,318	96,703	41,863	205,243	1,752,128
18							
19							
20	Adjustment for below the line items						179,643
21	Total charges'						<u>1,931,771</u>

Prepared By: kas
Reviewed By: pjb

Otter Tail Power Company
Charitable Contributions
Actual 12 Months Ending 12/31/07

Line No.	(A)	(B)
	Account 426.1/5371 Donations:	
1	Minnesota	223,934 (1)
2	Allowable Portion of Minnesota Contributions (50%)	111,967 (3)
3	Total Company	546,077 (2)
4	(1) B-6, Page 2 of 6 (2) <i>12/07 Financial Statement, Page 12, (A/C 426.1/5371.0000)</i> (3) Minnesota allows 1/2 of qualified charitable contributions.	

Prepared By: kas
Reviewed By: pjb

Otter Tail Power Company
Depreciation Expense-Production
Actual Year Ending December 31, 2007

	(A)	(B)	(C)	(D)	(E)	(F)
Line No.		MINNESOTA	NORTH DAKOTA	SOUTH DAKOTA	FERC	TOTAL
1						
2						
3	PRODUCTION	(1) 4,891,607	3,527,901	785,021	9,636	9,214,165
4						
5	PLUS: HYDRO LICENSING	(1) 25,619	18,155	4,090	50	47,913
6						
7	TOTAL PRODUCTION	4,917,226	3,546,055	789,111	9,685	9,262,078
8						
9						
10						
11	BASE DEMAND	(3) 3,534,759	2,549,090	567,254	6,962	6,658,065
12						
13	PEAK DEMAND	(2) 1,382,467	996,966	221,857	2,723	2,604,012
14						
15						
16	TOTAL PRODUCTION	4,917,226	3,546,055	789,111	9,685	9,262,078
		(1) B-7, PAGE 2 OF 2				
		(2) Total Production X Peaking Demand Factor			28.11%	(4)
		(3) Total Production X Base Demand Factor			71.89%	(4)
		(4) C-1, PAGE 1 OF 2				

Prepared By: kas
Reviewed By: pjb

Otter Tail Power Company
Jurisdictional Depreciation Information
Actual Year Ending December 31, 2007

	(A)	(B)	(C)	(D)	(E)	(F)
	DEPRECIATION EXPENSE	Minnesota	North Dakota	South Dakota	FERC	Total
Line No.	12 MO ENDED 12/31/07					
1	STEAM(EXCL UN TR & ORT)	4,286,705	3,078,427	687,993	8,287	8,061,412
2	HYDRO	45,207	32,036	7,217	87	84,547
3	I.C. & OTHER	559,695	417,438	89,811	1,261	1,068,206
4	ORTONVILLE	0	0	0	0	0
5						
6	TOTAL PRODUCTION	4,891,607	3,527,901	785,021	9,636	9,214,165
7						
8	TRANSMISSION	2,048,582	1,527,896	328,726	42,536	3,947,740
9	DISTRIBUTION	3,985,561	3,918,044	850,943	21,444	8,775,992
10						
11	GENERAL(EXCL TRANSP 392,390.2 & WHSE					
12	390.3,393,394.1 & CAP A&G)	1,208,321	995,003	216,679	6,255	2,426,258
13	Gain on Wahpeton Office	(5,576)				(5,576)
14	FLEET SRVC CNTR; (1)	0	0	0	0	0
15	CENTRAL STORES CLEARING; (1)	(57,339)	(44,139)	(9,643)	(317)	(111,438)
16	AIRPLANE; (1)	34,906	26,870	5,870	193	67,840
17	GAIN OR LOSS ON VEHICLES (1)	32,260	24,833	5,425	178	62,697
18	TOTAL GENERAL	1,212,572	1,002,568	218,332	6,309	2,439,781
19						
20	SUBTOTAL	12,138,322	9,976,409	2,183,022	79,925	24,377,678
21						
22	INTANGIBLE					
23	COMPUTER SOFTWARE					410,801
24	HYDRO LICENSING (2)	25,619	18,155	4,090	50	47,913
25						
26	CARRYING COSTS BSP ACQ.					0
27						
28	TOTAL					24,836,391
29						
30	Less: Carrying Costs BSP Acq. (a/c 421.5)					
31	Add: Big Stone Acq. Adj. Amortiz. Writeoff (a/c 425.31)					0
32	Spiritwood Amortization (a/c 407)					
33						
34	Total Depreciation (agrees to FERC Income Statement)					24,836,391 (3)
35						
36						
37						
38	(1) Spread to jurisdiction on P90 factor from 2006 COSS (latest available). Each state's separate COSS					
39	run for P90 factor; FERC = difference to reach 100%. (These should match the factors on p 4 of A-1.)					
40		MN	51.453954%			
41		ND	39.608527%			
42		SD	8.653354%			
43		FERC	0.284165%			
44			100.000000%			
45						
46	(2) Spread using same proportion as Hydro.					
47						
48	(3) Above			24,836,391		
49	Central Stores Clearing (390.3 and 393)			-	(4)	
50	Add Back Airplane Charged Direct			-	(4)	
51				24,836,391		
52	Monthly Financial Statements (non-FERC)			24,836,391		
53	Difference from FERC (rounding)			0		
54						
55	(4) Loyal D's depreciation schedules, tab "Total After ARO Related". Per Depreciation Accountant, these items lose					
56	jurisdictional identity when clearing through O & M or capital costs					
57						
58	(5) Reconciling Items to the FERC F/S per Loyal Demmer's Schedule on tab "Total After ARO Related"					

Source: Depreciation Schedules prepared by Accounting: Loyal D. Tab "Total for Regulatory Purposes"

V:\RS\Revenue_Requirements\COSS\2007\Actual COSS Supporting Worksheets\Depr for cost serv study 2007.xls]Total for Regulatory Purposes:

Prepared By: kas
Reviewed By: pjb

Recap Of Big Stone Capitalized Costs All Jurisdictions Actual Year Ending December 31, 2007

	(A)	(B)	(C)	(D)	(E)	(F)	
Line No.		Minnesota	North Dakota	South Dakota	FERC	Total	
1	Rate Base	A/C 186.10	A/C 186.20	A/C 186.30	A/C 186.40		
2		(1)			(1)		
3							
4	Rate Base Balance At 12/31/06	0	138,973	12,552	0	151,525	(2)
5							
6	Rate Base Balance At 12/31/07	0	98,298	8,878	0	107,176	(3)
7							
8	Average Rate Base Balance	0	118,635	10,715	0	129,351	
9							
10	Amortization Amount Ties to Page 2 of 2		40,675	3,675	(4)		

(1) Capitalized costs were written off in 1987 per 1987 W/P B-8, Page 1 Of 4.

(2) 2006 COSS.

Costs approved for rate base treatment and amortization over the remaining life of Big Stone Plant
Ordered By NDPSC Per Docket Number PU-401-88-374 Dated 12/20/88.

(3) 2006 balance less amount of amortization from B-8, page 2 of 2. Agrees to FERC 186.0 Detail file located in the
2007 Actual Year Supporting Workpaper Folder, less \$1 carried over from 2006.

(4) The amortization for the year is booked to A/C 406.20 & 406.30 (B-8, Page 2 Of 2)
and is included as Depreciation Expense for the current year.

Recap Of Big Stone Capitalized Costs
All Jurisdictions
Actual Year Ending December 31, 2007

Prepared By: kas
Reviewed By: pjb

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)
	BU	CC	Acct	Sub	FERC1	FERC2	YTD Bal
1	010	1000	5220	4000	40600	00000	44,349.60
2							
3							
4							
5							
6							
7	10/17/2008	AMORTIZATION - ACQUISITION ADJUSTMENT (115) & BIG STONE DEFERRED CHARGES (186)					
8		JURISDICTIONAL DEPRECIATION INFORMATION					
9			54,877,319.15		323818		
10							
11							
12		MINNESOTA	NORTH DAKOTA	SOUTH DAKOTA	FERC	TOTAL	
13	RESERVES (Ending)						
14	BIG STONE ACQ ADJ						
15							
16	STEAM	641,448.55	472,310.37	93,488.64	7,255.85	1,214,503.41	
17	TRANSMISSION	22,350.77	17,959.41	3,533.07	727.27	44,570.52	
18	DISTRIBUTION	210.83	194.59	40.10	2.68	448.20	
19							
20	TOTAL A/C 115	664,010.15	490,464.37	97,061.81	7,985.80	1,259,522.13	Acct 1799
21							
22	Big Stone Deferred Charges Reserve		772,826.50	180,643.01		953,469.51	Acct 1860.2500
23							
24							
25	AMORTIZATION						
26							
27	BIG STONE						
28	406.20 & .30	0.00	40,675.08	3,674.52	0.00	44,349.60	
29	406.11/41	25,231.88	17,880.44	4,027.95	48.78	47,189.05	
30							
31	TOTAL PRODUCTION	25,231.88	58,555.52	7,702.47	48.78	91,538.65	
32							
33	TRANSMISSION						
34	406.11/41	898.26	669.95	144.15	18.66	1,731.02	
35							
36							
37	DISTRIBUTION						
38		7.90	7.77	1.69	0.04	17.40	
39							
40							
41	TOTAL 406	26,138.04	59,233.24	7,848.31	67.48	93,287.07	
42							
43	MN GAIN ON WAHPETON OFFICE						
44	GENERAL PLANT	(5,576.28)				(5,576.28)	
45							
				Check total		87,710.79	to depr sum - Recap 406

Source: Depreciation Schedules prepared by Accounting: Loyal D. Tab "acct. 115 & 186".

V:\IRS\Revenue_Requirements\COSS\2007\2007 Actual Year Supporting Worksheets\Depr for cost serv study 2006.xls\acct. 115 & 186

Prepared by: kas
Reviewed by: pjb

Otter Tail Power Company Analysis of Investment Tax Credit Actual Year Ending December 31, 2007

(A) (B) (C) (D) (E) (F)

(Non Utility) - (Below the Line Expense)

Line No.		ACCOUNT 411.4		ACCOUNT 411.5		ACCOUNT 255
		DEBIT	CREDIT	DEBIT	CREDIT	NET
1	Balance at 12/31/06 (1)	0	0	0	0	(8,180,661)
2						
3	2007 CURRENT YEAR ACTIVITY:					
4	Current Year ITC Recapture (3)	0	0	0	0	
5	Current Year ITC Amortization (2)	0	(1,135,984)	0	(673)	
6						
7	TOTAL 2007 ACTIVITY	0	(1,135,984)	0	(673)	1,136,657 (2)
8						
9						
10	Balance at December 31, 2007					(7,044,004) (4)

- (1) PER 2006 COSS W/P B-10, PAGE 1 OF 3.
(2) B-10, PAGE 2 OF 3. (673) amount is from 1976
(3) B-10, PAGE 3 OF 3
(4) TIES TO GL AND B-10, PAGES 2 AND 3

Otter Tail Power Company
Analysis of Investment Tax Credit
Actual Year Ending December 31, 2007

Prepared by: kas
Reviewed by: pjb

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
	YEAR	CO	BU	CC	ACCT	SUB	ACTY	PROJ	FERC1	FERC2	SumOfBalance
1	2007	100	10	0	5410	4114	0	0	41104	0	(\$610,097.00)
2	2007	100	20	0	5410	4114	0	0	41104	0	(\$224,909.00)
3	2007	100	30	0	5410	4114	0	0	41104	0	(\$300,978.00)
4											(1,135,984.00)
5											
6	YEAR	CO	BU	CC	ACCT	SUB	ACTY	PROJ	FERC1	FERC2	SumOfBalance
7	2007	100	10	0	5410	4115	0	0	41105	0	(361.00)
8	2007	100	20	0	5410	4115	0	0	41105	0	(132.00)
9	2007	100	30	0	5410	4115	0	0	41105	0	(180.00)
10											(673.00)
11											
12	YEAR	CO	BU	CC	ACCT	SUB	ACTY	PROJ	FERC1	FERC2	SumOfBalance
13	2007	100	10	0	2525	0	0	0	25500	0	(3,780,627.46)
14	2007	100	20	0	2525	0	0	0	25500	0	(1,392,909.45)
15	2007	100	30	0	2525	0	0	0	25500	0	(1,870,468.01)
16											(7,044,004.92)
17											
18	<u>Year</u>	<u>Comp</u>	<u>BU</u>	<u>CC</u>	<u>Acct</u>	<u>Sub</u>	<u>Activity</u>	<u>Proj</u>	<u>FERC1</u>	<u>FERC2</u>	<u>Dec-06 Bal</u>
19		100	70	0	5410	4114	0	0	41104	0	(1,135,984.00)
20											
21		100	70	0	5410	4115	0	0	41105	0	(673.00)
22											
23		100	70	0	2525	0	0	0	25500	0	(7,044,004.92)

Source: FERC GL Account data for appropriate year.

Otter Tail Power Company
Analysis of Investment Tax Credit
Actual Year Ending December 31, 2007

Prepared by: kas
Reviewed by: pjb

BOOK AMORTIZATION LIFE		33 1/3 YEARS		TAX YEAR 2007		
(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line No.	ITC UTILIZED AS OF 12/31/06	ITC LOST FROM 83-86 RAR	ITC RECAPTURE FOR 2006	REMAINING AFTER ITC ADJUSTMENTS	2007 AMORTIZATION	REMAINING BALANCE AS OF 12/31/2007
1	1971	0		0	0	0
2	1972	0		0	0	0
3	1973	3,807		3,807	3,807	(0)
4	1974	14,181		14,181	10,636	3,545
5	1975	204,930		204,930	87,827	117,103
6	1976	251,451		251,451	107,765	143,686
7	1976	2,243		2,243	673	1,570
8	1977	461,668		461,668	106,539	355,129
9	1978	280,813		280,813	52,653	228,160
10	1979	211,846		211,846	33,449	178,397
11	1980	1,748,076		1,748,076	238,374	1,509,702
12	1981	247,936		247,936	29,752	218,184
13	1982	2,370,190		2,370,190	253,949	2,116,241
14	1983	1,047,201		1,047,201	101,342	945,859
15	1984	423,878		423,878	37,401	386,477
16	1985	667,094		667,094	54,089	613,005
17	1986	245,349		245,349	18,401	226,948
18	1987	0		0	0	0
19	1988	0		0	0	0
20	1989	0		0	0	0
21						
22	TOTAL	8,180,663	0	8,180,663	1,136,657	7,044,006 (1)
23		=====	=====	=====	=====	=====
24				SM 10		

(1) Difference of \$2 due to rounding.

Otter Tail Corp (OTP & Corp)

Prepared by: kas

Schedule M-1

(Separate Return Basis)

2007 YE Accrual

(C) = Corporate

(P) = OTP

(B) = Both

Line No.		(A)	(B) Federal	(C) MN	(D) ND
		(X) = Completed			
1	X	P Net Income Per Books - OTP	24,497,584	24,497,584	24,497,584
2	X	C Net Income Per Books - Corporate (includes subs but not OTP)	29,463,120	29,463,120	29,463,120
3	X	P Income Tax - A/C (409.1) 5410.1001 - 1004	7,824,116	7,824,116	7,824,116
4	X	P Income Tax - A/C (409.2) 5410.2001 - 2004	2,236,841	2,236,841	2,236,841
5	X	P Income Tax - A/C (409.2-99) 5410.4120	0	0	0
6	X	P Income Tax - A/C (410.1 & 411.1) 5410.4101 & 5410.4111	3,467,360	3,467,360	3,467,360
7	X	P Income Tax - A/C (410.2 & 411.2) 5410.4102 & 5410.4112	564,660	564,660	564,660
8	X	P Income Tax - A/C (411.4) 5410.4114	(1,168,484)	(1,168,484)	(1,168,484)
9	X	P Income Tax - A/C (411.5) 5410.4115	(673)	(673)	(673)
10	X	C Income Taxes - Corporate	(3,002,341)	(3,002,341)	(3,002,341)
11	X	B Net Income Before Tax (Consolidated)	63,882,183	63,882,183	63,882,183
12	X	P Elimination of Subsidiaries' Profit on OTP's Books	-	0	0
13	X	C Elimination of Subsidiaries' Profit on Corporate's Books	(33,211,381)	(33,211,381)	(33,211,381)
14	X	P Net Income Before Tax (OTP)	37,421,404	37,421,404	37,421,404
15	X	C Net Income Before Tax (Corporate)	(6,750,602)	(6,750,602)	(6,750,602)
16	X	B Net Income Before Tax (Otter Tail Corp: OTP & Corp)	30,670,802	30,670,802	30,670,802
17		(tied to Taxable Income by Co. w/s) proof \$38,131,006			
18		ADDITIONS:			
19	(2)	X Book Provision - Property Repairs (Storm Damages)	-	0	0
20	(2)	X Book Provision - Injuries & Damages	-	0	0
21	(2)	X Book Provision - Workmen's Comp	289,299	289,299	289,299
22	(2)	X Book Provision - Post Retire Med Benefit (FAS 106)	4,382,031	4,382,031	4,382,031
23	(2)	X Book Provision - Post Employ Med Benefit (FAS 112)	232,271	232,271	232,271
24	(2)	X Book Provision - Supplemental Pension Reserve	2,683,522	2,683,522	2,683,522
25	(2)	X Book Provision - Bad Debts	1,010,891	1,010,891	1,010,891
26	(2)	X Book Provision - Loan Pools	400	400	400
27	(1)	X C Non-Qual. Retire Savings - Employee Contribs (book expense)	2,275,411	2,275,411	2,275,411
28	(1)	X C Non-Qual. Retire Savings - COLI Non-deductible premiums	1,155,856	1,155,856	1,155,856
29	(1)	X C Corp. Insurance Reserve : Tax deductible payments	(114,858)	(114,858)	(114,858)
30	(16)	X C Executive Stock Incentive Plan - Book Provision	1,734,720	1,734,720	1,734,720
31	(6)	X Employee Stock Purchase Program (ESPP) - Book Expense	257,203	257,203	257,203
32	(6)	X Stock Options - Book Compensation Expense	90,468	90,468	90,468
33	(6)	X Book Provision for Deferred Settlement (book expense)	-	-	-
34	(6)	X B Meal Allowances - 50% Disallowed	124,488	124,488	124,488
35	(10)	X P Accrued Vacation Pay	87,932	87,932	87,932
36	(5)	X CIP Tracker Account - MN (Net)	544,894	544,894	544,894
37	(6)	X Interest Capitalized on Construction (Taxable)	1,714,223	1,714,223	1,714,223
38	(4)(8)	X Amort - Acq Costs on Big Stone Plant	93,287	93,287	93,287
39	(1)	X Lobbying Expense (Non-Deductible)	216,448	216,448	216,448
40	(6)	X Sales Promotion Expense (Book Expense)	-	0	0
41	(1)	X Amortization of Loss on Reacquired Debt	327,174	327,174	327,174
42	(1)	X Actual Gain on Reacquired Bonds	-	0	0
43	(1)	X Penalties	-	0	0
44	(1)	X C Corp. Owned Life Insurance (Non-Deduct Premiums)	410,327	410,327	410,327
45	(6)	X B Restricted Stock Incentive - All (Book expense)	285,852	285,852	285,852
46	(1)	X C Affordable Housing Operating Loss (Book Basis)	353,301	353,301	353,301
47	(6)	X Capitalized A & G (Books expensed)	2,175,260	2,175,260	2,175,260
48	(8)	X NDSBIC Partnership (K-1 taxable income)	-	0	0
49	(1)	X Customer Rebates Capitalized Current Yr (IRS audit 1993-94)	53,357	53,357	53,357
50	(9), (6)	X Federal Empowerment Zone Tax Credit	9,000	N/A	N/A
51	(1)	X Mapleton Industrial Park - Book Writedown	-	0	0
52	(6)	X CIAC - Contribution in Aid of Constr.-Taxable Current Yr	-	0	0
53	(15)	X MN PUC Order (Recovery of MISO Day 2 Costs)	-	-	-
54	(13)	X PBR Refund to ND	-	0	0
55	(1)	X BSP II Land Write-off	-	0	0
56	(13)	X Disallowed rate base (book deduction to inc, not allowed for tax)	-	0	0
57	(6)	X ETI - Disallowance of Expenses Related to Exempt Income	-	0	0
58	(9), (6)	X Income from Property	(1,225,884)	(1,330,811)	(1,225,884)
59	(6)	X Highway Reimbursements	(253,900)	(253,900)	(253,900)
60		(leave blank)			
61		Total Additions to Book Income	18,912,973	18,799,046	18,903,973
62					
63		SUBTRACTIONS:			
64	(1)	X B Federally Exempt Interest	12,918	N/A	N/A
65	(1)	X B State Exempt Interest (Where Allowed)	N/A	N/A	0
66		X Pensions (FAS 87 & 88) Contributions (tax deductible)	-	0	0
67	(6)	X Pensions (FAS 87 & 88) Non-taxable Book Income	(4,511,835)	(4,511,835)	(4,511,835)
68	(2)	X Charges - Property Repairs (Storm Damages)	-	0	0
69	(2)	X Charges - Injury & Damages	(8,436)	(8,436)	(8,436)
70	(2)	X Charges - Workmen's Comp	297,299	297,299	297,299
71	(2)	X Charges - Medical Self Insurance	-	0	0
72	(2)	X Charges - Post Retire Medical Benefit (FAS 106)	2,054,606	2,054,606	2,054,606
73	(2)	X Charges - Post Employ Med Benefit (FAS 112)	261,834	261,834	261,834
74	(9), (6)	X Medicare Part D (nontaxable subsidy)	1,054,510	N/A	1,054,510
75	(6)	X Amortization of Medicare Part D Capitalized (non-taxable subsidy)	N/A	N/A	N/A
76	(2)	X Charges - Supplemental Pension Reserve	1,078,998	1,078,998	1,078,998
77	(2)	X Charges - Bad Debts	987,693	987,693	987,693
78	(2)	X Charges - Loan Pool Write-offs	(187)	(187)	(187)
79	(1)	X C Non-Qual. Retire Savings - Distributions (tax deduction)	193,171	193,171	193,171
80	(1)	X C Non-Qual. Retire Savings - COLI non-taxed cash value increase	1,746,764	1,746,764	1,746,764
81	(1)	X C Executive Stock Incentive Plan - Tax Deductible Payments	770,330	770,330	770,330
82	(1)	X C Corp. Owned Life Insurance (Cash value increase/death benefit)	1,267,738	1,267,738	1,267,738
83	(6)	X Payments for Deferred Settlement (tax deduction)	84,131	84,131	84,131
84	(10)	X Removal Costs	3,949,203	3,949,203	3,949,203
85		X CIP Tracker Account - MN (Net)	-	0	0
86	(10)(9)	X Tax Depreciation	27,328,728	32,275,349	27,347,236
87	(10)(9)	X Book Depreciation	(24,646,032)	(24,646,032)	(24,646,032)
88		X 30% Bonus Depr - Add back for MN only	N/A	0	N/A
89	(6)	X AFDC Charged to Construction (Book)	2,257,062	2,257,062	2,257,062
90		X Dividend Received Deduction (0 X 70%)	-	0	N/A
91	(6)	X ACRS Retirements-Ordinary Loss	N/A	N/A	N/A

Otter Tail Corp (OTP & Corp)
Schedule M-1
 (Separate Return Basis)
2007 YE Accrual

Prepared by: kas

(C) = Corporate
 (P) = OTP
 (B) = Both

Line No.		(A) (X) = Completed	(B) Federal	(C) MN	(D) ND
92	(6)	X	MACRS Retirements-Ordinary Loss	N/A	N/A
93	(10)	X	Utility Dividend Paid Credit: (37,099 X 3.60 X (14/35)	53,423	53,423
94	(10)	X	(40,000 X 6.75 X (14/35) X 99.4%)	107,352	107,352
95	(1)	X	Amortized Gain on Recquired Bonds	118	118
96	(1)	X	Early Bond Redemption in Current Year - Tax Deductible	1,375,206	1,375,206
97	(6)	X	ESOP Deduction (Leveraged)	1,879,028	1,879,028
98	(1)	X	C Affordable Housing Operating Loss (Tax Basis)	150,000	150,000
99	(13)	X	Customer Rebates Amortization (IRS audit 1993-94)	N/A	N/A
100	(13)	X	Amortization of Asbestos Removed (IRS 1993 audit)	N/A	N/A
101	(6)	X	Capitalized A & G (Tax Amortization)	N/A	N/A
102	(6)	X	NDSBIC Partnership (book income not taxable)	0	0
103	(6)	X	Restricted Stock Units (post '05) - (Tax Deduct for Employee Gain)	130,692	130,692
104	(6)	X	B Restricted Stock Incentive - (Tax Deduction for Employee Gain)	161,689	161,689
105	(6)	X	B Restricted Stock Incentive - (Tax Deduction for Dividends)	10,401	10,401
106	(1)	X	C Restricted Stock Incentive - (Tax Deduct: R/E)(offset is to R/E)	153,804	153,804
107	(1)	X	C Employees' Gain on Stock Options Pre 123R (no book exp taken)	2,350,903	2,350,903
108	(1)	X	C Employees' Gain on Stock Options Post 123R (book exp taken)	346,565	346,565
109	(6)	X	CIAC - Contribution in Aid of Constr.-Amort for Tax	N/A	N/A
110	(1)	X	Mapleton Industrial Park - Taxable Loss on Sale	35,075	35,075
111	(1)	X	Mark to Market Derivative Accounting	428,693	428,693
112	(6)	X	Sec. 174 R&D Deductions	0	0
113	(6)	X	Sec. 162 costs	0	0
114	(6)	X	ADR Repair Allowance	504,232	504,232
115	(1)	X	ETI Exclusion Including Gross-up	0	0
116	(1)	X	Sec. 199 Production Activities Deduction	933,418	N/A
117			Total Subtractions from Book Income	22,799,094	21,871,266
118					
119			Taxable Income Before Deduction for State Taxes	26,784,681	27,703,509
120			Less: MN Estimated & Extension Tax Paid for Current Year	984,994	N/A
121			ND Estimated & Extension Tax Paid for Current Year	667,607	N/A
122			Other State Estimated & Extension Tax Paid for CY	13,101	N/A
123	X		Add'l State Taxes Paid/(Rec'd) for Prior Years	(281,639)	N/A
124			Taxable Income	25,400,619	27,703,509
125	X		Apportionment Factors	100.0000%	37.0940%
126			Apportioned Income	25,400,619	10,276,340
127	X		Tax Rate	35.0%	6.5%
128			Tax Liability Before Adjustments	8,890,216	667,962
129	(11)(12)	X	Minnesota Minimum Fee & ND Incremental Tax Rate Adj.	N/A	(355)
130			Income Tax Liability Before Tax Credits	8,890,216	667,607
131					
132	(6)	X	Less: Federal Fuel Tax Credit (OTP only)	-	N/A
133	(6)	X	Wind Energy Tax Credits	(3,342)	0
134	X		Research & Development Tax Credit (OTP only)	(75,237)	N/A
135	X		North Dakota Tax Credits (OTP only)	N/A	-
136	(6)	X	Federal Empowerment Zone Tax Credit (M-1 addition)	(9,000)	N/A
137	(1)	X	C Affordable Housing Tax Credits	(285,000)	N/A
138			Otter Tail Corporation Tax Liability (Separate Return)	8,517,637	667,607
139	X		Adj due to filing unitary returns & subs' tax agreement	743,613	(1,666,783)
140			Adj due to Sec 199 calc (separate vs consolidated)	0	N/A
141			Total Current Tax Liability	9,261,250	(999,176)
142					
143	X		Total Current Tax Liability (Federal + MN + ND)	9,630,559	
144	X		Plus or (minus) "Other State" Tax Liability (OTP's portion + Unitary Adj)	(267,227)	
145	X		Grand Total Tax Liability (OTP only)	9,363,332	
146					
147					
148					
149					
150					
151					
152	X		Operating & Non-Operating Breakdown		
153	X		Tax on Operating Income	7,440,182	(1,160,022)
154	X		Tax on Non-Operating Income (includes LIHTC)	1,821,068	160,846
155	X		Total Current Tax Liability (OTP only)	9,261,250	(999,176)
156					
157			** (Note: Must include Other State unitary adj in Non-Operating Tax)	(267,227)	
158	X		Grand Total Current Tax Liability (OTC)	9,363,332	
159					

(A) tie to below

(A) tie to above

- (1) Not used in COSS, Below the Line or Corporate
 (2) B-12 Page 4 of 10
 (3) Not used
 (4) B-12 Page 5 of 10
 (5) Not used
 (6) B-12 Page 6 of 10
 (7) Not used

- (8) B-12 Page 7 of 10
 (9) B-12 Page 8 of 10
 (10) Posted directly to input summary
 (11) Entered directly in MN COSS T1071
 (12) Entered directly in ND COSS V1097
 (13) Not used in COSS
 (15) Not used as revenue not reduced on B-1
 (16) Not used as not an expense on utility books

Prepared by: kas
Reviewed by: pjb

Otter Tail Power Company Operating Reserve Charges and Provisions Actual Year 2007

		(A)	(B)	(C)
			PROVISIONS	CHARGES
Line No.		(1)	(2)	
1	Storm Damages	0	0	
2	Injuries and Damages	0	(8,436)	
3	Workers' Compensation	289,299	297,299	
4	Medical Insurance	0	0	
5	Post Retirement Medical Benefits	4,382,031	2,054,606	
6	Post Employment Medical Benefits	232,271	261,834	
7	Supplemental Pension Reserve	2,683,522	1,078,998	
8	Bad Debts	1,010,891	987,693	
9	Loan Pools	400	(187)	
10	TOTAL	8,598,414	4,671,807	

(1) B-12, PAGE 1 OF 10, Additions
(2) B-12, PAGE 1 & 2 OF 10, Subtractions

Workpapers B-12, pages 1, 2 and 3 of 9 are copies of Workpaper SM-1
2006 year-end tax accrual

Prepared by: kas
Reviewed by: pjb

Otter Tail Power Company
Above the Line Big Stone Schedule M Adjustment
Actual Year 2007

DEBIT = ADDBACK TO SCHEDULE M
CREDIT = ADDITIONAL DEDUCTION ON SCHEDULE M

	(A)	(B)	(C)	(D)	(E)	(F)
Line No.		MINNESOTA (1)	NORTH DAKOTA (1)	SOUTH DAKOTA (1)	FERC (1)	TOTAL (1)
1						
2	A/C 406.1 Rate Allowed Amort Of Adjustment	26,138	18,558	4,174	67	48,937
3	A/C 406.20 Rate Allowed Amort Of Deferred Costs	0	40,675	0	0	40,675
4	A/C 406.21 Rate Allowed Amort Of Adjustment	0	0	0	0	0
5	A/C 406.30 Rate Allowed Amort Of Deferred Costs	0	0	3,675	0	3,675
6	A/C 406.31 Rate Allowed Amort Of Adjustment	0	0	0	0	0
7	A/C 406.41 Rate Allowed Amort Of Adjustment	0	0	0	0	0
8	Total Schedule M Adjustment Per Year End Accrual	26,138	59,233	7,848	67	93,287

(2)

- (1) AGREES TO B-8, PAGE 2 OF 2.
(2) AGREES TO B-12, PAGE 1 OF 10

Prepared by: kas
Reviewed by: pjb

Otter Tail Power Company
Other Schedule M Additions And Deductions
Actual Year 2007

	(A)	(B)	(C)	(D)	
OTHER SCHEDULE M ADDITIONS AND DEDUCTIONS NOT SHOWN SEPARATELY ON INPUT SUMMARY					
ADDBACKS ON SCHEDULE M					
Line No.	Fed	Miscellaneous Adj to Federal AOIBT			
		MN	ND		
1	Employee Stock Purchase Program (ESPP) - Book Expense	257,203	257,203	257,203	(1)
2	Stock Options - Book Compensation Expense	90,468	90,468	90,468	(1)
3	Book Provision for Deferred Settlement (book expense)	0	0	0	(1)
4	Meals - 50% Disallowance	124,488	124,488	124,488	(1)
5	Restricted Stock Incentive - All (Book expense)	285,852	285,852	285,852	(1)
6	Income From Property	(1,225,884)	(1,330,811)	(1,225,884)	(1)
7	Non-Qual. Retire Savings - Employee Contribs (book expense) (transferred to Corporate)	0	0	0	(1)
8	CIAC - Contribution in Aid of Constr.-Taxable Current Yr	0	0	0	(1)
9	Interest Capitalized on Construction (Taxable)	1,714,223	1,714,223	1,714,223	(1)
10	Sales Promotion Expense (Book Expense)	0	0	0	(1)
11	Federal Empowerment Zone Tax Credit	9,000	N/A	N/A	(1), (3)
12	Capitalized A & G (Books expensed)	2,175,260	2,175,260	2,175,260	(1)
13	Highway Reimbursements	(253,900)	(253,900)	(253,900)	(1)
14	Federal Fuel Tax Credit	0	N/A	N/A	
15	TOTAL FEDERAL ADDBACKS ON SCHEDULE M	3,176,710	3,062,783	3,167,710	

DEDUCTIONS ON SCHEDULE M

16	MACRS Retirements - Ordinary Loss	N/A	0	N/A	0	N/A	(2)
17	ACRS Retirements - Ordinary Loss	N/A	0	N/A	0	N/A	(2)
18	Non-Qual. Retire Savings - Distributions (tax deduction) (Transferred to Corporate)	0	0	0	0	0	(2)
19	Amortization Of Mapping Expense	0	0	0	0	0	(2)
20	Leveraged ESOP Deduction	1,879,028	0	1,879,028	0	1,879,028	(2)
21	Pensions (FAS 87 & 88) Non-taxable Book Income	(4,511,835)	0	(4,511,835)	0	(4,511,835)	(1)
22	Payments for Deferred Settlement (tax deduction)	84,131	0	84,131	0	84,131	(2)
23	Restricted Stock Units (post '05) - (Tax Deduct for Employee Gain)	130,692	0	130,692	0	130,692	(2)
24	Restricted Stock Incentive - (Tax Deduction for Employee Gain)	161,689	0	161,689	0	161,689	(2)
25	CIAC - Contribution in Aid of Constr.-Amort for Tax	N/A	0	N/A	0	N/A	(2)
26	Restricted Stock Incentive - (Tax Deduction for Dividends)	10,401	0	10,401	0	10,401	(2)
27	AFDC Charged to Construction (Book)	2,257,062	0	2,257,062	0	2,257,062	(2)
28	ADR Repair Allowance	504,232	0	504,232	0	504,232	(2)
29	Sec. 174 R&D Deductions	0	0	0	0	0	(2)
30	Sec. 162 costs	0	0	0	0	0	(2)
31	Amortization of Medicare Part D Capitalized (non-taxable subsidy)	N/A	0	N/A	0	N/A	(1)
32	Medicare Part D (nontaxable subsidy)	1,054,510	0	N/A	0	1,054,510	(1)
33	Capitalized A & G (Tax Amortization)	N/A	0	N/A	0	N/A	(2)
34	Total Federal Deductions On Schedule M	1,569,910		515,400		1,569,910	
35							
36	NET MAJOR SCHEDULE M OTHER ADDITIONS/(DEDUCTIONS)	1,606,800		2,547,383		1,597,800	
37							
38							

INPUT SUMMARY ENTRY **(1,606,800)** 940,583 (4) (9,000) (4)
(accomplishes footnote on direction of sign)

- (1) B-12, PAGE 1 OF 10
(2) B-12, PAGE 2 OF 10
(3) See B-12, page 9 of 10 for explanation
(4) Use as a check to Pg 8 Calculation

NOTE - SIGNS ARE OPPOSITE ON THE INPUT SUMMARY AS COSS SCHEDULE M DEDUCTIONS ARE SHOWN AS POSITIVE AMOUNTS THERE.

Prepared by: kas
Reviewed by: pjb

Otter Tail Power Company Directly Assigned Schedule M Adjustments Actual Year 2007

	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	SCHEDULE M ADDITIONS/(DEDUCTIONS)	MINNESOTA	NORTH DAKOTA	SOUTH DAKOTA	FERC	TOTAL
1	BIG STONE ADJUSTMENT (1)	26,138	59,233	7,848	67	93,287
2						0
3	CASS COUNTY ECON DEV (Ended 2003) (2)		0			0
4	TOTAL	26,138	59,233	7,848	67	93,287

(1) B-12, PAGE 5 OF 10.

(2) B-12, PAGE 1 OF 10.

NOTE: INPUT SUMMARY SIGNS ARE OPPOSITE

Prepared by: kas
Reviewed by: pjb

Otter Tail Power Company
Adjustments To Federal AOIBT For State Tax Calculations
Actual Year 2007

	(A)	(B)	(C)	
Line No.	SCHEDULE M ADDITIONS/(DEDUCTIONS) ITEMS SHOWN ON SEPARATE LINE	MINNESOTA	NORTH DAKOTA	
1	CHANGE IN EXCESS TAX DEPRECIATION	<u>(4,946,621)</u>	<u>(18,508)</u>	(2)
2				
3				
4	CHANGE IN ACRS & MACRS - ORDINARY LOSS	<u>0</u>	<u>0</u>	(2)
5				
6				
7	CHANGE IN INCOME FROM ADR, ACRS & MACRS PROPERTY	<u>0</u>	<u>0</u>	(1)
8				
9				
10	MISCELLANEOUS ADJUSTMENTS TO AOIBT			
11				
12	Amortization of Medicare Part D Capitalized (non-taxable subsidy)	0	0	(4)
13				
14	Medicare Part D (nontaxable subsidy)	1,054,510	0	(4)
15				
16	Income From Property	(104,927)	0	(1)
17				
18	Federal Empowerment Zone Tax Credit	<u>(9,000)</u>	<u>(9,000)</u>	(3)
19				
20	TOTAL MISCELLANEOUS ADJUSTMENTS TO AOIBT	<u>940,583</u>	<u>(9,000)</u>	
22				

- (1) B-12, PAGE 1 OF 10
 (2) B-12, PAGE 1 OF 10 (Change in MN law allowed additional depreciation in 2002)
 (3) B-12, PAGE 1 OF 10; see B-12, page 9 of 9 for explanation
 (4) B-12, PAGE 2 OF 10

NOTE: INPUT SUMMARY SIGNS ARE THE SAME.

Prepared by: kas
Reviewed by: pjb

**Adjustment for Economic Development Expenses
Actual 2007**

Line (A) (B) (C) (D) (E)
No.

1	SUMMARY OF INPUTS:				
2	Input Summary B, page 3 of 7:				
3	Line 2 MN Sales Expenses		198,119		
4	Line 4 SD Sales Expenses		38,078		
5	Line 5 Other Sales Expenses		(236,197)		
6	Line 21 Outside Services		0		
7			<u>(0)</u>		

8					
9					
10					
11			(2)	(2)	
12		(1)	MN	SD	
13		Amount	83.88%	16.12%	
14	912 Demonstrating & selling expenses	236,197	198,119	38,078	
15	923-69 Outside Services	0	0	0	
16	Total	236,197	198,119	38,078	

(1) B-13, p. 2 of 2

(2) Percentage should equal current year COSS C-1 Factors in proportion to the total calculated by adding both jurisdictions together. See cell G29 for formula.

This adjustment is made to directly assign economic development expenses to Minnesota and South Dakota. Without this adjustment, North Dakota receives its directly assigned amount plus approximately 40% of other economic development expenses.

Economic Development - Minnesota and South Dakota

Prepared by: kas

Reviewed by:

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
	YEAR	CO	BU	CC	ACCT	SUB	ACTY	PROJ	FERC1	FERC2	SumOfBalance	MONTH
1	2007	100	20	690	5103	0	30	100692	40100	91200	-	0
2	2007	100	30	10	5100	1100	30	100010	40100	91200	21,590.30	0
3	2007	100	30	10	5101	2600	30	100010	40100	91200	127.45	0
4	2007	100	30	10	5116	0	30	100010	40100	91200	-	0
5	2007	100	30	10	5106	2000	30	100010	40100	91200	184.00	0
6	2007	100	30	20	5100	1100	30	100020	40100	91200	399.00	0
7	2007	100	30	40	5100	1100	30	100040	40100	91200	1,867.51	0
8	2007	100	30	20	5106	2000	30	100040	40100	91200	184.00	0
9	2007	100	30	90	5100	1100	30	100090	40100	91200	3,470.37	0
10	2007	100	30	90	5101	2600	30	100090	40100	91200	40.01	0
11	2007	100	30	40	5106	2000	30	100040	40100	91200	-	0
12	2007	100	30	40	5116	0	30	100040	40100	91200	-	0
13	2007	100	30	80	5106	2000	30	100080	40100	91200	-	0
14	2007	100	30	100	5100	1100	30	100100	40100	91200	9,416.50	0
15	2007	100	30	100	5101	2600	30	100100	40100	91200	202.14	0
16	2007	100	30	100	5106	2000	30	100100	40100	91200	46.00	0
17	2007	100	30	110	5101	2000	30	100110	40100	91200	15.31	0
18	2007	100	30	140	5100	1100	30	100140	40100	91200	7,783.48	0
19	2007	100	30	140	5101	2600	30	100140	40100	91200	84.68	0
20	2007	100	30	140	5103	0	30	100140	40100	91200	545.18	0
21	2007	100	30	140	5106	2000	30	100140	40100	91200	53.00	0
22	2007	100	30	620	5100	1100	30	100620	40100	91200	159,604.86	0
23	2007	100	30	620	5100	1100	30	102017	40100	91200	9,773.61	0
24	2007	100	30	620	5100	1100	30	102037	40100	91200	2,667.26	0
25	2007	100	30	620	5101	2500	30	100620	40100	91200	793.53	0
26	2007	100	30	620	5101	2600	30	100620	40100	91200	1,290.53	0
27	2007	100	30	620	5101	2600	30	102017	40100	91200	9.79	0
28	2007	100	30	620	5101	2600	30	102037	40100	91200	14.91	0
29	2007	100	30	620	5102	0	30	100620	40100	91200	261.95	0
30	2007	100	30	620	5103	0	30	100620	40100	91200	3,915.80	0
31	2007	100	30	620	5103	0	30	102017	40100	91200	97.63	0
32	2007	100	30	620	5103	0	30	102037	40100	91200	273.20	0
33	2007	100	30	620	5105	0	30	100620	40100	91200	4,469.57	0
34	2007	100	30	620	5106	3000	30	100620	40100	91200	16.00	0
35	2007	100	30	620	5106	4000	30	100620	40100	91200	178.22	0
36	2007	100	30	620	5107	0	30	100620	40100	91200	81.23	0
37	2007	100	30	620	5116	0	30	100620	40100	91200	636.26	0
38	2007	100	30	690	5101	2500	30	100693	40100	91200	-	0
39	2007	100	30	690	5101	2600	30	100693	40100	91200	-	0
40	2007	100	30	690	5102	0	30	100693	40100	91200	-	0
41	2007	100	30	690	5103	0	30	100693	40100	91200	2,949.46	0
42	2007	100	30	690	5116	0	30	100693	40100	91200	3,154.74	0
											236,197.48	

Source:

December FERC Database

Prepared By: kas
Reviewed By: pjb

Otter Tail Power Company
Advertising Expense
Actual 12 Months Ending 12/31/07

Line No.	(A)	(B)
	Adjustment to remove advertising expense:	
1	Account 913 Advertising expenses	(299,289)
2	(Sales Expense)	
3		
4		
5	Account 930.1 General advertising expenses	(613,716)
6	(Administrative & General Expense)	
7		
8	Total	<u>(913,005)</u>
9		
10		
11	Amount excluded in 930.1 above that should be	
12	included with 930.2	<u>1,578</u> (1)
Note: Minnesota and North Dakota prohibit all except safety, conservation and educational advertising from rates. Adjustments entered using same signs as above. (1) Adjustment located on Input Summary H572 to Increase Miscellaneous Expense for amounts that relate to informing shareholders of annual meetings, posting of financial results, etc that should have been posted to account 930.2.		

Prepared By: kas
Reviewed By: pjb

Advertising Expense 2007

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
Line No.	YEAR	CO	BU	CC	ACCT	SUB	ACTY	PROJ	FERC1	FERC2	SumOfBalance	MONTH
1	2007	100	030	0010	5117	0000	0020	100010	40100	90900	5,952.40	12
2	2007	100	030	0020	5117	0000	0020	100020	40100	90900	4,912.55	12
3	2007	100	030	0030	5117	0000	0020	100030	40100	90900	7,362.43	12
4	2007	100	030	0040	5117	0000	0020	100040	40100	90900	1,688.33	12
5	2007	100	030	0060	5117	0000	0020	100060	40100	90900	3,686.99	12
6	2007	100	030	0080	5117	0000	0020	100080	40100	90900	1,532.70	12
7	2007	100	030	0090	5100	1100	0040	102035	40100	90900	1,009.01	12
8	2007	100	030	0090	5107	0000	0040	102035	40100	90900	158.74	12
9	2007	100	030	0090	5117	0000	0020	102034	40100	90900	60.00	12
10	2007	100	030	0100	5117	0000	0020	100100	40100	90900	728.50	12
11	2007	100	030	0110	5117	0000	0020	100110	40100	90900	1,240.00	12
12	2007	100	030	0140	5117	0000	0020	100140	40100	90900	10,186.15	12
13	2007	100	030	0270	5100	1100	0020	100270	40100	90900	2,996.21	12
14	2007	100	030	0270	5100	1100	0020	102184	40100	90900	425.40	12
15	2007	100	030	0270	5100	1100	0020	102305	40100	90900	51.39	12
16	2007	100	030	0270	5100	1100	0020	103176	40100	90900	729.08	12
17	2007	100	030	0270	5100	1100	0040	100270	40100	90900	18,020.70	12
18	2007	100	030	0270	5101	2600	0040	100270	40100	90900	494.41	12
19	2007	100	030	0270	5102	0000	0040	100270	40100	90900	3,084.66	12
20	2007	100	030	0270	5103	0000	0020	100270	40100	90900	68.00	12
21	2007	100	030	0270	5103	0000	0040	100270	40100	90900	1,314.20	12
22	2007	100	030	0270	5106	4000	0040	100270	40100	90900	84.71	12
23	2007	100	030	0270	5110	1000	0020	100270	40100	90900	11,123.63	12
24	2007	100	030	0270	5110	1000	0040	100270	40100	90900	10,159.17	12
25	2007	100	030	0270	5116	0000	0040	100270	40100	90900	1,492.11	12
26	2007	100	030	0270	5117	0000	0020	100270	40100	90900	226,626.20	12
27	2007	100	030	0270	5117	0000	0040	100270	40100	90900	1,347.60	12
28	2007	100	030	0690	5100	1100	0040	100693	40100	90900	6,869.05	12
29	2007	100	030	0690	5103	0000	0040	100693	40100	90900	138.08	12
30	2007	100	030	0690	5116	0000	0040	100693	40100	90900	3,243.80	12
31	2007	100	030	0840	5100	1100	0020	103176	40100	90900	168.89	12
32	2007	100	030	0840	5110	1000	0020	102184	40100	90900	345.00	12
33	\$327,300.09											
34												
	YEAR	CO	BU	CC	ACCT	SUB	ACTY	PROJ	FERC1	FERC2	SumOfBalance	MONTH
36	2007	100	030	0010	5117	0000	0025	100010	40100	91300	405.00	12
37	2007	100	030	0020	5117	0000	0025	100020	40100	91300	355.75	12
38	2007	100	030	0030	5100	1100	0025	100030	40100	91300	4,550.84	12
39	2007	100	030	0030	5117	0000	0025	100030	40100	91300	507.88	12
40	2007	100	030	0040	5117	0000	0025	100040	40100	91300	1,384.12	12
41	2007	100	030	0060	5117	0000	0025	100060	40100	91300	290.80	12
42	2007	100	030	0140	5117	0000	0025	100140	40100	91300	3,270.92	12
43	2007	100	030	0270	5100	1100	0025	100270	40100	91300	2,292.38	12
44	2007	100	030	0270	5103	0000	0025	100270	40100	91300	440.80	12
45	2007	100	030	0270	5106	4000	0025	100270	40100	91300	578.00	12
46	2007	100	030	0270	5107	0000	0025	100270	40100	91300	117.15	12
47	2007	100	030	0270	5110	1000	0025	100270	40100	91300	34,579.69	12
48	2007	100	030	0270	5110	2000	0025	100270	40100	91300	5,624.25	12
49	2007	100	030	0270	5116	0000	0025	100270	40100	91300	400.00	12
50	2007	100	030	0270	5117	0000	0025	100270	40100	91300	244,490.94	12
51	\$299,288.52											

Prepared By: kas
Reviewed By: pjb

Advertising Expense 2007

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
	YEAR	CO	BU	CC	ACCT	SUB	ACTY	PROJ	FERC1	FERC2	SumOfBalance	MONTH
53	YEAR	CO	BU	CC	ACCT	SUB	ACTY	PROJ	FERC1	FERC2	SumOfBalance	MONTH
54	2007	100	010	0760	5103	0000	0026	100760	40100	93001	102.00	12
55	2007	100	010	0760	5117	0000	0026	100760	40100	93001	3,297.00	12
56	2007	100	010	1100	5117	0000	0026	101100	40100	93001	76.00	12
57	2007	100	020	0310	5117	0000	0026	100310	40100	93001	57.00	12
58	2007	100	020	0760	5117	0000	0026	100760	40100	93001	80.00	12
59	2007	100	030	0010	5117	0000	0026	100010	40100	93001	16,363.83	12
60	2007	100	030	0010	5117	0000	0026	100610	40100	93001	225.00	12
61	2007	100	030	0020	5117	0000	0026	100020	40100	93001	26,871.38	12
62	2007	100	030	0030	5100	1110	0026	100270	40100	93001	626.53	12
63	2007	100	030	0030	5100	2100	0026	100270	40100	93001	(626.53)	12
64	2007	100	030	0030	5116	0000	0026	100030	40100	93001	60.87	12
65	2007	100	030	0030	5117	0000	0026	100030	40100	93001	11,069.70	12
66	2007	100	030	0040	5116	0000	0026	100040	40100	93001	107.48	12
67	2007	100	030	0040	5117	0000	0026	100040	40100	93001	15,378.35	12
68	2007	100	030	0060	5116	0000	0026	100060	40100	93001	19.68	12
69	2007	100	030	0060	5117	0000	0026	100060	40100	93001	10,404.86	12
70	2007	100	030	0080	5116	0000	0026	100080	40100	93001	79.37	12
71	2007	100	030	0080	5117	0000	0026	100080	40100	93001	9,473.91	12
72	2007	100	030	0090	5101	2500	0040	006116	40100	93001	467.55	12
73	2007	100	030	0090	5101	2600	0040	006116	40100	93001	179.65	12
74	2007	100	030	0090	5117	0000	0026	100090	40100	93001	1,081.54	12
75	2007	100	030	0100	5117	0000	0026	100100	40100	93001	12,557.21	12
76	2007	100	030	0110	5106	3000	0026	100110	40100	93001	2.00	12
77	2007	100	030	0110	5116	0000	0026	100110	40100	93001	215.76	12
78	2007	100	030	0110	5117	0000	0026	100110	40100	93001	18,197.61	12
79	2007	100	030	0140	5116	0000	0026	100140	40100	93001	52.56	12
80	2007	100	030	0140	5117	0000	0026	100140	40100	93001	9,514.52	12
81	2007	100	030	0150	5117	0000	0026	100150	40100	93001	70.62	12
82	2007	100	030	0270	5100	1100	0026	100270	40100	93001	24,798.02	12
83	2007	100	030	0270	5100	1100	0026	100272	40100	93001	866.65	12
84	2007	100	030	0270	5100	1120	0026	100270	40100	93001	4,509.64	12
85	2007	100	030	0270	5101	2600	0026	100270	40100	93001	25.66	12
86	2007	100	030	0270	5103	0000	0026	100270	40100	93001	833.23	12
87	2007	100	030	0270	5103	0000	0026	100272	40100	93001	147.44	12
88	2007	100	030	0270	5110	1000	0026	100270	40100	93001	94,301.82	12
89	2007	100	030	0270	5116	0000	0026	100270	40100	93001	30.17	12
90	2007	100	030	0270	5117	0000	0026	100270	40100	93001	324,352.44	12
91	2007	100	030	0270	5117	0000	0040	000000	40100	93001	(4.00)	12
92	2007	100	030	0610	5117	0000	0026	100610	40100	93001	3,537.96	12
93	2007	100	030	0620	5117	0000	0026	100620	40100	93001	1,731.14	12
94	2007	100	030	0690	5117	0000	0026	100693	40100	93001	392.00	12
95	2007	100	030	0700	5117	0000	0040	100700	40100	93001	60.00	12
96	2007	100	030	0720	5100	1110	0026	100270	40100	93001	31.65	12
97	2007	100	030	0720	5100	2100	0026	100270	40100	93001	(31.65)	12
98	2007	100	030	0830	5117	0000	0026	100830	40100	93001	80.00	12
99	2007	100	030	0840	5100	1110	0026	100270	40100	93001	3,851.46	12
100	2007	100	030	0840	5100	2100	0026	100270	40100	93001	(3,851.46)	12
101	2007	100	030	0840	5116	0000	0026	100840	40100	93001	9,015.07	12
102	2007	100	030	0840	5117	0000	0026	100840	40100	93001	32.00	12
103											\$600,714.69	
104												
105	2007	100	70	550	5117	0	40	100550	40100	93001	14,380.30	12
106											\$14,380.30	
107												
108												
109	2006	100	70	550	5117	0	800	100550	40100	93001	\$0.00	12
110												
111											\$327,300.09	
112											\$1,378.62 (1)	
113											<u>\$328,678.71</u>	
114												
115											\$299,288.52	
116											\$13,001.68	
117											\$600,714.69	
118											<u>\$913,004.89</u>	
119												
120											<u><u>\$1,241,683.60</u></u>	

(1) B-14; Page 4.

Otter Tail Power Company
Minnesota, North Dakota and South Dakota
Power Services Expense Adjustment for Non-Asset Based Wholesale Transactions
Actual 12 months ending December 31, 2007

	(A)	(B)	(C)	(D)	(E)	(F)
						2007 Total Non-Asset Wholesale Expense Adjustment to Input Summary
Line No.		Input Summary location	virtual Expense Adjustment	Buy/Resell Adjustment		
	Production expense adjustment (506 and 556)					
1	Base Adjustment (1)	(B summary p 2 of 7 line 4)	\$262,246	\$855,088		\$1,117,334
2	Peak Adjustment (1)	(B summary p 2 of 7 line 5)	\$129,939	\$423,684		\$553,623
3	Total 506 and 556 production adjustment		\$392,186	\$1,278,771		\$1,670,957
4						
5						
6						
7						
8						
9	Transmission Expense adjustment (561)		\$0	\$0		\$0
10						
11	A & G Expense Adjustment (920, 921 and 926) Salaries, Supplies, Pension & Benefits					
12	PRODUCTION	(B summary p 3 of 7 line 11)	\$11	\$36		\$48
13	TRANSMISSION (2)	(B summary p 3 of 7 line 12)	\$4	\$14		\$18
14	DISTRIBUTION (2)	(B summary p 3 of 7 line 13)	\$8	\$25		\$32
15	CUSTOMER ACCOUNTS (2)	(B summary p 3 of 7 line 14)	\$5	\$18		\$23
16	CUSTOMER SERVICE & INFO (2)	(B summary p 3 of 7 line 15)	\$2	\$6		\$8
17	Total A & G Expense Adjustment (920, 921 and 926)		\$30	\$99		\$129
18						
19	A & G Expense Adjustment (930, 935)					
20	GENERAL ADVERTISING	(B summary p 3 of 7 line 31)	\$0	\$0		\$0
21	MISC, RENTS, MAINTENANCE	(B summary p 3 of 7 line 32)	\$0	\$0		\$0
22			\$0	\$0		\$0
23						
24	Total A & G Expense Adjustment		\$392,216	\$1,278,870		\$1,671,087
25						(3)
26						
27						

(1) BASE/PEAK SPLIT
JANUARY 2007 Actual

BASE	PEAK
66.87%	33.13%

(Ratios come from C-1)

(2) LABOR RATIOS: 2007 Actual

PRODUCTION	TRANSMISSION	DISTRIBUTION	ACCOUNTING	SERVICE
36.81%	14.09%	25.04%	17.90%	6.16%

(Ratios come from C-2)

Only asset-based margins are included above the line in utility financial statements. Non-asset-based wholesale revenue and purchased power is reported below the line. It is necessary to allocate other appropriate costs to B/L wholesale sales. This adjustment is made to remove expenses related to non-asset based wholesale sales from above-the-line utility expenses.

The signs are opposite on the input summary as we want to reduce total expenses.

(3) FERC account balance B-15, page 4, x non-asset based portion b-15 page 2 x base-peak split or labor ratios

Calculation of Net Wholesale Margins

Line No.	(A)	(B)	(C)	(D)
		Gross Margin	Allocated Costs	Net Margin
1	Wholesale margins (1)			
2	Non-asset based	4,772,983	1,671,087	3,101,897
3			<u>1,671,087</u>	
4				
5				
6				Allocated costs
7	Sales	MWH	% of total	
8				
9	Asset-based (1)	364,414	4.5%	165,834
10	Non-asset based (1)	3,672,137	45.0%	1,671,087
11				
12	Subtotal	<u>4,036,551</u>	<u>49.5%</u>	<u>1,836,921</u>
13	FERC (5)	3,648	0.0%	1,660
14	Retail (2)	<u>4,118,034</u>	<u>50.5%</u>	<u>1,874,002</u>
15	Total Sales	<u>8,158,233</u>	<u>100.0%</u>	<u>3,712,583</u>
16				
17				
18				
19	Allocation of Power Services costs (cc 760)			
20	Labor (3)	\$2,947,320		
21	Overhead rate (4) 11%	324,205		
22	Other expenses (3)	441,057		
23	Total to allocate	<u>3,712,583</u>		
24				
25				
26				
27	(1) Monthly margin worksheet; See B-15, Pages 5 & 6.			
28	(2) Page 5 of Statistical Book			
29	(3) FERC account database; B-15, Page 3			
30	(4) Accounting Circular No. 13 Revised April 2007			
31	(5) Cost of Energy Data File; Current Year MWH's for Municipals			

For MN Report
1,326,631
145,929
198,526
<u>1,671,087</u>

Power Services Expenses - 2007

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
	YEAR	CO	BU	CC	ACCT	SUB	ACTY	PROJ	FERC1	FERC2	SumOfBalance	With Loading
1	2007	100	010	0760	5100	1100	0870	100760	40100	55700	1,483,540.58	\$1,646,730.04
2	2007	100	010	0760	5100	1100	0870	100760	40100	57502	1,173,754.28	\$1,302,867.25
3	2007	100	010	0760	5100	1100	0870	100760	40100	57503	258,528.44	\$286,966.57
4	2007	100	010	0760	5100	1120	0960	100760	40100	55700	288.86	\$320.63
5	2007	100	010	0760	5100	1120	1230	100760	40200	57603	31,208.31	\$34,641.22
6							Total Labor				\$2,947,320.47	\$3,271,525.72
7												
8	2007	100	010	0760	5101	2500	0870	100760	40100	55700	11,517.92	11,517.92
9	2007	100	010	0760	5101	2500	0870	100760	40100	57503	937.09	937.09
10	2007	100	010	0760	5101	2500	1080	100760	40100	92600	252.00	252.00
11	2007	100	010	0760	5101	2600	0870	100760	40100	55700	3,615.39	3,615.39
12	2007	100	010	0760	5101	2600	0870	100760	40100	57503	20.00	20.00
13	2007	100	010	0760	5101	2700	0870	100760	40100	55700	155.59	155.59
14	2007	100	010	0760	5102	0000	0870	100760	40100	55700	42,598.05	42,598.05
15	2007	100	010	0760	5102	0000	0870	100760	40100	57503	510.00	510.00
16	2007	100	010	0760	5102	0000	1230	100760	40200	57603	15,750.00	15,750.00
17	2007	100	010	0760	5103	0000	0870	100760	40100	55700	18,135.48	18,135.48
18	2007	100	010	0760	5103	0000	0870	100760	40100	57503	1,294.21	1,294.21
19	2007	100	010	0760	5103	0000	1080	100760	40100	92600	35.41	35.41
20	2007	100	010	0760	5103	0000	1580	100760	40100	55700	68.00	68.00
21	2007	100	010	0760	5105	0000	0870	100760	40100	55700	4,078.20	4,078.20
22	2007	100	010	0760	5105	0000	1230	100760	40200	57603	6,000.00	6,000.00
23	2007	100	010	0760	5106	2000	0530	100760	40100	55600	58,132.71	58,132.71
24	2007	100	010	0760	5106	2000	0870	100760	40100	55700	133,894.15	133,894.15
25	2007	100	020	0760	5106	2000	0530	100760	40100	55600	-6,457.61	(6,457.61)
26	2007	100	010	0760	5106	3000	0870	100760	40100	55700	51.32	51.32
27	2007	100	010	0760	5106	3000	0870	100760	40100	57503	4.80	4.80
28	2007	100	010	0760	5106	4000	0870	100760	40100	55700	336.00	336.00
29	2007	100	010	0760	5106	4000	0870	100760	40100	57503	38.29	38.29
30	2007	100	010	0760	5107	0000	0870	100760	40100	55700	236.00	236.00
31	2007	100	010	0760	5107	0000	1230	100760	40200	57603	3,126.84	3,126.84
32	2007	100	010	0760	5110	2000	0870	100760	40100	55700	145,976.72	145,976.72
33	2007	100	010	0760	5116	0000	0870	100760	40100	55700	750.60	750.60
34												
35	Total Other Expenses										\$441,057.16	\$441,057.16
36	Total Power Services Expenses										\$3,388,377.63	\$3,712,582.88

Source: Report is generated by Sharon Henderson per the parameters described below.

Note: From Sharon's report, the first set of numbers are CC 760, Acct 5100 and Project 100760.
For the 2nd set of #'s, CC 760 Accts 5101 thru 5117 and 5240 only and exclude FERC 565, 566, 909, 913, 928, 930, and 930.1 as they are already accounted for elsewhere.

Note: Make sure to redefine the database "db" range located in the upper left corner drop-down box.

Power Services Expenses - 2007 - check of FERC account totals

Line No.	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I) Totals	(J) YTD totals OH Loading
	BU	CC	ACCT	SUB	ACTY	PROJ	FERC1	FERC 2	SumOfBalance	
1	10	760	5100	1100	870	100760	40100	55600	1,483,540.58	1,646,730.04
2	10	760	5100	1120	960	100760	40100	55600	288.86	320.63
3	10	760	5101	2500	870	100760	40100	55600	11,517.92	11,517.92
4	10	760	5101	2600	870	100760	40100	55600	3,615.39	3,615.39
5	10	760	5101	2700	870	100760	40100	55600	155.59	155.59
6	10	760	5102	0	870	100760	40100	55600	42,598.05	42,598.05
7	10	760	5103	0	870	100760	40100	55600	18,135.48	18,135.48
8	10	760	5103	0	1580	100760	40100	55600	68.00	68.00
9	10	760	5105	0	870	100760	40100	55600	4,078.20	4,078.20
10	10	760	5106	2000	530	100760	40100	55600	58,132.71	58,132.71
11	10	760	5106	2000	870	100760	40100	55600	133,894.15	133,894.15
12	10	760	5106	3000	870	100760	40100	55600	51.32	51.32
13	10	760	5106	4000	870	100760	40100	55600	336.00	336.00
14	10	760	5107	0	870	100760	40100	55600	236.00	236.00
15	10	760	5110	2000	870	100760	40100	55600	145,976.72	145,976.72
16	10	760	5116	0	870	100760	40100	55600	750.60	750.60
17	20	760	5106	2000	530	100760	40100	55600	(6,457.61)	(6,457.61)
18	System control and load dispatching								1,896,917.96	2,060,139.20
19										
20										
21	10	760	5100	1120	1230	100760	40100	92000	-	-
22	30	760	5100	1220	1230	100760	40100	92000	-	-
23	Admin and general salaries								-	-
24										
25	10	760	5100	1100	870	100760	40100	57502	1,173,754.28	1,302,867.25
26	10	760	5100	1100	870	100760	40100	57503	258,528.44	286,966.57
27	10	760	5101	2500	870	100760	40100	57503	937.09	937.09
28	10	760	5101	2600	870	100760	40100	57503	20.00	20.00
29	10	760	5102	0	870	100760	40100	57503	510.00	510.00
30	10	760	5103	0	870	100760	40100	57503	1,294.21	1,294.21
31	10	760	5106	3000	870	100760	40100	57503	4.80	4.80
32	10	760	5106	4000	870	100760	40100	57503	38.29	38.29
33	MISO Market Admin Costs								1,435,087.11	1,592,638.21
34										
35	10	760	5100	1120	1230	100760	40200	57603	31,208.31	34,641.22
36	10	760	5102	0	1230	100760	40200	57603	15,750.00	15,750.00
37	10	760	5105	0	1230	100760	40200	57603	6,000.00	6,000.00
38	10	760	5107	0	1230	100760	40200	57603	3,126.84	3,126.84
39	Computer Software Maintenance								56,085.15	59,518.06
40										
41	30	760	5107	0	870	100760	40100	92100	-	-
42	Office supplies and expenses								-	-
43										
44	10	760	5101	2500	1080	100760	40100	92600	252.00	252.00
45	10	760	5103	0	1080	100760	40100	92600	35.41	35.41
46	Employee pensions and benefits								287.41	287.41
47										
48	TOTAL								3,388,377.63	3,712,582.88
49									-	\$0.00

(1)

NOTE: Account 566 for Power Services is not included as this is MISO Schedule 10 charges which are based on retail energy and demand only and is already appropriately accounted for in the input summary. Also see note on Page 4.

@ Combine FERC 557 with 556

(1) Use the Totals for the different FERC Accts in the Formula on B-15, Page 1.

Otter Tail Power Company
Base and Peak Demand Split Data
January 2007 & 2008 Actual and January 2009 & 2010 Budget

Prepared by: kas
Reviewed By: pjb

Line No.	(A)	(B)	(C)	(D)	(E)	(F)
		Plant Capacity - KW			Estimated Cost of New Capacity	
		Steam Hydro	Other	Total	Base Load	Peaking
		(A)	(B)	(C)	(D)	(E)
1	January 2007 - Actual	553,644 (1)	137,570 (1)	691,214	\$1,964 (1)	\$558 (1)
2	January 2008 - Actual	554,138 (2)	132,617 (2)	686,755	\$2,384	\$572
3	January 2009 - Forecast	554,138	132,617	686,755	\$2,443	\$586
4	January 2010 - Forecast	554,138	132,617	686,755	\$2,504	\$601

Calculation of Base Demand and Peaking Demand Factors
Total Current Cost (TCC) = (A X D) + (B X E)
Peaking Demand Factor (PDF) = (C X E) / TCC
Base Demand Factor (BDF) = 1 - PDF

January 2007 - Actual	TCC =	\$1,164,120,876	Data To Be Used For:
	PDF =	33.13%	Actual Invest Balances @ 12/31/2006
	BDF =	66.87%	Actual 2007 Expenses
January 2008 - Actual	TCC =	\$1,396,653,135	Actual Invest Balances @ 12/31/2007
	PDF =	28.11%	Forecast 2008 Expenses
	BDF =	71.89%	
January 2009 - Forecast	TCC =	\$1,431,569,463	Forecast Invest Balances @ 12/31/2008
	PDF =	28.11%	Forecast 2009 Expenses
	BDF =	71.89%	
January 2010 - Forecast	TCC =	\$1,467,358,700	Forecast Invest Balances @ 12/31/2009
	PDF =	28.11%	Forecast 2010 Expenses
	BDF =	71.89%	

(1) W/P C-1, 2006 Actual Year COSS

(2) January financial statement, Electrical Operating Statistics (Page 13), Net Plant Capacity.

Prepared By: kas
Reviewed By: pjb

Otter Tail Power Company
Labor Ratios
Actual Years 2006 & 2007

Line No.	(A) Function Labor	(B) Actual Year 2006		(C) Portion Of Total	(D) Actual Year 2007		(E) Portion Of Total
		Amount			Amount		
		(2)			(4)		
1	Production (3)	\$14,038,057		37.42%	\$14,906,456		36.81%
2							
3	Transmission	5,597,171		14.92%	5,706,607		14.09%
4							
5	Distribution	8,819,148		23.51%	10,138,266		25.04%
6							
7	Customer Accounts	6,708,295		17.88%	7,247,999		17.90%
8							
9	Customer Service & Information, & Sales (1)	2,351,239		6.27%	2,495,421		6.16%
10							
11							
12							
13	Subtotal	37,513,910		100.00%	40,494,749		100.00%
14							
15	Administrative & General	18,055,474			19,595,620		
16							
17	Total Labor Expense	55,569,384			60,090,369		
18							
19		Used For:			Used For:		
20		-Investment Balances			-Investment Balances @ 12/31/07		
21		@12/31/06			-Expenses For Actual		
22					Year End 12/31/07		
23							

Source: Respective Year's FERC Form 1, Page 354

(1) Customer Service & Information Labor And Sales Labor Are Combined Since They Are Allocated On The Same Factor (C1).

(2) 2006 FERC Form I, page 354, lines 20-27

(3) Regional Market Labor is combined with Production Labor as costs are related to Power Services.

(4) 2007 FERC Form 1, page 354, lines 20-27, C-2, Page 2 of 2

Name of Respondent Otter Tail Corporation	This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2007/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	8,904,066		
4	Transmission	3,619,526		
5	Regional Market	1,432,283		
6	Distribution	5,044,763		
7	Customer Accounts	7,247,999		
8	Customer Service and Informational	1,673,304		
9	Sales	822,117		
10	Administrative and General	17,823,993		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	46,568,051		
12	Maintenance			
13	Production	4,538,899		
14	Transmission	2,087,081		
15	Regional Market	31,208		
16	Distribution	5,093,503		
17	Administrative and General	1,771,627		
18	TOTAL Maintenance (Total of lines 13 thru 17)	13,522,318		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	13,442,965		
21	Transmission (Enter Total of lines 4 and 14)	5,706,607		
22	Regional Market (Enter Total of Lines 5 and 15)	1,463,491		
23	Distribution (Enter Total of lines 6 and 16)	10,138,266		
24	Customer Accounts (Transcribe from line 7)	7,247,999		
25	Customer Service and Informational (Transcribe from line 8)	1,673,304		
26	Sales (Transcribe from line 9)	822,117		
27	Administrative and General (Enter Total of lines 10 and 17)	19,595,620		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	60,090,369		60,090,369
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

ALLOCATION FACTORS
MINNESOTA CLASSES

2007 Actual factors D & C - Original Classes

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
	TOTAL	MN	ND	SD	FERC	CLASS TOTAL	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE
Line No.										
1	598,234	304,929	236,559	55,954	792	304,929	83,790	6,940	55,556	149,098
2	604,225	304,929	236,559	55,954	6,783	304,929	83,790	6,940	55,556	149,098
3	757,342	340,610	332,687	77,778	6,267	340,610	79,402	9,690	70,220	110,820
4	998,227	432,549	459,319	106,359	-	432,549	98,491	19,736	98,942	78,275
5	3,918,074	2,074,148	1,457,625	382,540	3,761	2,074,148	462,453	34,651	339,030	1,173,848
6	4,430,839	2,277,133	1,720,495	429,450	3,761	2,277,133	498,778	35,253	354,693	1,173,848
7	129,675	60,947	57,014	11,714	-	60,947	48,360	1,286	9,851	393
8	135,857	63,559	59,913	12,381	4	63,559	49,735	1,449	10,837	416
9	135,784	63,511	59,901	12,372	-	63,511	49,735	1,449	10,812	393
10	4,185,546	1,980,427	1,760,035	445,084	-	1,980,427	-	-	-	-
11	3,688,552	1,621,835	1,716,671	350,046	-	1,621,835	-	-	-	-
12	29,240,646	13,664,904	12,850,789	2,724,953	-	13,664,904	4,350,684	448,416	3,270,938	865,714
13	173,474	84,014	73,215	16,245	-	84,014	50,423	1,303	22,691	911
14	135,879	63,581	59,913	12,381	4	63,581	49,735	1,449	10,837	438
15	40,923	18,775	18,040	4,108	-	18,775	3,179	53	69	-

	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED			
16	0	2,080	3,120	440	3,503	402			
17	-	2,080	3,120	440	3,503	402			
18	5,732	5,455	3,084	12,350	38,801	5,056			
19	7,095	5,243	4,461	48,607	63,196	8,503			
20	-	21,905	22,624	11,346	-	8,291			
21	5,834	21,905	22,624	27,231	117,067	19,900			
22	154	105	494	72	198	34			
23	378	115	515	28	83	3			
24	378	115	515	28	83	3			
25	-	1,980,427	-	-	-	-			
26	-	1,621,835	-	-	-	-			
27	251,085	30,411	145,796	2,439,416	1,536,420	326,024			
28	235	125	752	4,678	2,409	487			
29	378	115	515	28	83	3			
30	111	-	-	9,622	5,055	686			

**ALLOCATION FACTORS
NORTH DAKOTA CLASSES**

2007 Actual factors D & C - Original Classes

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
	TOTAL	MIN	ND	SD	FERC	CLASS TOTAL	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE
Line No.										
1	D1	598,234	304,929	236,559	55,954	792	83,948	4,282	78,714	58,200
2	D2	604,225	304,929	236,559	55,954	6,783	83,948	4,282	78,714	58,200
3	D3	757,342	340,610	332,687	77,778	6,267	81,375	6,402	90,235	69,378
4	D4	998,227	432,549	459,319	106,359	-	111,558	12,711	124,762	61,432
5	E1	3,918,074	2,074,148	1,457,625	382,540	3,761	432,402	24,607	448,292	491,634
6	E2	4,430,839	2,277,133	1,720,495	429,450	3,761	490,575	25,529	451,012	491,634
7	C1	129,675	60,947	57,014	11,714	-	44,201	916	10,870	123
8	C2	135,857	63,559	59,913	12,381	4	46,011	1,091	11,880	140
9	C3	135,784	63,511	59,901	12,372	-	46,011	1,091	11,876	132
10	C4	4,185,546	1,980,427	1,760,035	445,084	-	-	-	-	-
11	C5	3,688,552	1,621,835	1,716,671	350,046	-	-	-	-	-
12	C6	29,240,646	13,664,904	12,850,789	2,724,953	-	4,439,962	328,536	3,681,789	180,785
13	C7	173,474	84,014	73,215	16,245	-	45,597	943	18,374	305
14	C8	135,879	63,581	59,913	12,381	4	46,011	1,091	11,880	140
15	C9	40,923	18,775	18,040	4,108	-	3,722	42	38	-

	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED			
Line No.									
16	D1	0	2,939	346	5,237	588			
17	D2	-	2,939	346	5,237	588			
18	D3	1,096	2,797	10,010	57,405	7,982			
19	D4	1,550	3,821	30,451	94,738	12,522			
20	E1	-	18,381	8,940	-	8,667			
21	E2	712	18,381	21,459	175,691	20,800			
22	C1	27	545	45	225	36			
23	C2	69	572	18	85	14			
24	C3	69	572	18	85	14			
25	C4	-	-	-	-	-			
26	C5	-	-	-	-	-			
27	C6	51,098	159,285	1,908,048	1,848,130	242,692			
28	C7	37	624	3,790	3,130	385			
29	C8	69	572	18	85	14			
30	C9	19	-	7,564	6,036	619			

ALLOCATION FACTORS

SOUTH DAKOTA CLASSES

2007 Actual factors D & C - Original Classes

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
	TOTAL	MN	ND	SD	FERC	CLASS TOTAL	RESIDENTIAL	FARMS	GENERAL SERVICE	LARGE GENERAL SERVICE
Line No.										
1	598,234	304,929	236,559	55,954	792	55,954	18,115	1,835	15,629	18,398
2	604,225	304,929	236,559	55,954	6,783	55,954	18,115	1,835	15,629	18,398
3	757,342	340,610	332,687	77,778	6,267	77,778	15,933	1,998	18,871	19,908
4	998,227	432,549	459,319	106,359	-	106,359	24,333	4,021	24,691	19,191
5	3,918,074	2,074,148	1,457,625	382,540	3,761	382,540	97,326	8,855	91,733	170,496
6	4,430,839	2,277,133	1,720,495	429,450	3,761	429,450	104,373	8,981	92,642	170,496
7	129,675	60,947	57,014	11,714	-	11,714	8,902	344	2,255	30
8	135,857	63,559	59,913	12,381	4	12,381	9,339	390	2,453	36
9	135,784	63,511	59,901	12,372	-	12,372	9,339	390	2,447	33
10	4,185,546	1,980,427	1,760,035	445,084	-	445,084	-	-	-	-
11	3,688,552	1,621,835	1,716,671	350,046	-	350,046	-	-	-	-
12	29,240,646	13,664,904	12,850,789	2,724,953	-	2,724,953	805,754	119,232	751,822	54,435
13	173,474	84,014	73,215	16,245	-	16,245	9,361	349	4,467	98
14	135,879	63,581	59,913	12,381	4	12,381	9,339	390	2,453	36
15	40,923	18,775	18,040	4,108	-	4,108	575	10	12	-

	IRRIGATION	OUTDOOR LIGHTING	OPA	CONTROLLED WATER HEATING	CONTROLLED SERVICE INTERRUPT	CONTROLLED SERVICE DEFERRED			
16	0	437	630	114	653	143			
17	-	437	630	114	653	143			
18	524	1,154	594	3,332	13,584	1,880			
19	760	1,109	707	9,555	19,073	2,919			
20	-	4,808	4,127	3,020	-	2,175			
21	398	4,808	4,127	7,247	31,158	5,220			
22	11	5	115	16	26	10			
23	17	5	119	4	11	7			
24	17	5	119	4	11	7			
25	-	445,084	-	-	-	-			
26	-	350,046	-	-	-	-			
27	11,453	1,635	33,005	644,144	247,033	56,440			
28	12	5	170	1,279	412	92			
29	17	5	119	4	11	7			
30	3	-	-	2,561	816	131			

Otter Tail Power Company
Effective Tax Rates
Actual Year 2007

prepared by: kas
reviewed by: pjb

Line No.	(A)	(B)	(C)	(D)	(E)	(F)
1	TAX RATES:	(1)				(2)
2	FEDERAL	35.00%		SD SPECIAL HEARING FUND ASSESSMENT RATE:		0.0015
3	MINNESOTA	9.80%				
4	NORTH DAKOTA	6.50%				

		TOTAL	FEDERAL	MINNESOTA	NORTH DAKOTA
5	==> MINNESOTA				
6	INCOME		1,000	1,000	
7	MN INCOME TAX		98	9.80%	
8					
9			902	98.0	
10	FEDERAL TAX RATE		35.00%		
11					
12	TOTAL TAX		315.70		
13					
14	EFFECTIVE TAX RATES - MN	41.370%	31.570%	9.80%	
15					
16					
17	GROSS REVENUE CONVERSION FACTOR:	1 / (1 - TOTAL ETR)			1.705611

18	==> NORTH DAKOTA				
19	INCOME		1,000		1,000
20	ND / FEDERAL INCOME TAX		65.0		
21					
22			935.0		1,000
23	FEDERAL TAX RATE		35.00%		6.50%
24					
25	TOTAL TAX		327.3		65.0
26					
27	EFFECTIVE TAX RATES - ND	39.225%	32.725%		6.50%
28					
29					
30	GROSS REVENUE CONVERSION FACTOR:	1 / (1 - TOTAL ETR)			1.645413

31	==> SOUTH DAKOTA				
32	EFFECTIVE TAX RATES - SD	35.00%	35.00%	(NO STATE INCOME TAX IN SOUTH DAKOTA)	
33					
34					
35	SD GROSS REVENUE CONVERSION FACTOR:				
36	(INCLUDING RECOGNITION OF SD SPECIAL HEARING FUND ASSESSMENT)				
37					
38	WHERE "X" = GROSS REVENUE DEFICIENCY				
39	"Y" = CONVERSION FACTOR				
40	.0015 = SDPUC SPECIAL HEARING FUND ASSESSMENT				
41	35.00% = FEDERAL TAX RATE				
42					
43	$X = [X - .0015X - [(X - .0015X) * .34]] * Y$				
44	$X = [.9985X - (.9985X * .34)] * Y$				
45	$X = (.9985X - .33949X) * Y$				
46	$X = .65901XY$				
47	$1 = .65901Y$				
48	$Y =$				1.540773

49	==> TOTAL COMPANY	(3)	FED	MN	ND
50	EFFECTIVE TAX RATES - SYSTEM	39.0%	32.8%	3.7%	2.5%
51					
52					
53	GROSS REVENUE CONVERSION FACTOR:	1 / (1 - TOTAL ETR)			1.639344
	(1) C-4, PAGE 2 OF 2, W/S SM 3 from YE Tax Accrual (2) PER Susan Vukonich (Tax Dept) (3) FERC revenue apportioned to all 3 states to use system tax rate in FERC filing, C-4, PAGE 2 OF 2				

Otter Tail Corporation
(OTP and Corporate only)
Effective Tax Rate
YE Accrual 2007

C-4
Page 2 of 2
prepared by: kas
reviewed by:

Line No.	(A)	(B)	(C)	(D)	(E)
		FEDERAL	MN	ND	TOTAL
1	INCOME	1,000.00	1,000.00	1,000.00	
2	TAX EXPENSE DEDUCTIONS				
3	FEDERAL				
4	MINNESOTA	41.32			
5	NORTH DAKOTA	24.11			
6		-----	-----	-----	
7	SUBTOTAL	934.56	1,000.00	1,000.00	
8					
9	APPORTIONMENT FACTOR (OTP separate)	100%	42.1673%	37.0940%	
10		-----	-----	-----	
11	TAXABLE INCOME	934.56	421.67	370.94	
12					
13	TAX RATE	35.00%	9.80%	6.50%	
14		-----	-----	-----	
15					
16	TAX	327.10	41.32	24.11	
17					
18	EFFECTIVE TAX RATE	32.710%	4.132%	2.411%	0.393
19		=====	=====	=====	=====
20					
21	RATE TO USE: (INSERT FOR ROUNDING)	32.8%	3.7%	2.5%	39.0%
22		=====	=====	=====	=====
23					
24	For 2007 Year End Accrual, no significant change (.000). Review for Tax Return when final apportionment data is used				

Source: SM3 in Current Year Tax Accrual File or Located in Misc Workpaper File for Current Year COSS

Line No.24

	\$ 12,154,247	\$ 711,592

2

30 31

70393

45

47

48

50

52

30

65

7

19

ELECTRIC ONLY

OTTER TAIL POWER COMPANY
EMBEDDED COST OF PREFERRED STOCK
AVERAGE THIRTEEN MONTHLY BALANCES YEAR ENDING DECEMBER 31, 2007

Line No.	(A) DESCRIPTION	(B) YEAR OF ISSUE	(C) SHARES OUTSTANDING												(P) DIVIDEND RATE	(Q) AVERAGE MONTHLY BALANCE OUTSTANDING	(R) ANNUAL DIVIDEND
			(D) DEC	(E) JAN	(F) FEB	(G) MAR	(H) APR	(I) MAY	(J) JUN	(K) JUL	(L) AUG	(M) SEP	(N) OCT	(O) NOV			
		(1)															(2)
1	\$ 3.60 DIVIDEND SERIES - 1946		6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	216,000
2	\$ 4.40 DIVIDEND SERIES - 1950		2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	110,000
3	\$ 4.65 DIVIDEND SERIES - 1946		3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	139,500
4	\$ 6.75 DIVIDEND SERIES - 1993		4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	270,000
5																	
6	TOTAL		15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	735,500
7																	
8	TOTAL CUMULATIVE PREFERRED STOCK		15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	15,500,000	735,500

(1) APPROPRIATE MONTHLY FINANCIAL STATEMENTS

(2) DIVIDEND RATE X AVERAGE BALANCE OUTSTANDING

WEIGHTED COST OF CUMULATIVE PREFERRED STOCK																4.78%

****ELECTRIC ONLY****
OTTERTAIL POWER COMPANY
COMMON EQUITY
AVERAGE THIRTEEN MONTHLY BALANCES, ACTUAL YEAR ENDING DECEMBER 31, 2007

Line No.	(A) TITLE	(B) DEC (1)	(C) JAN	(D) FEB	(E) MAR	(F) APR	(G) MAY	(H) JUN	(I) JUL	(J) AUG	(K) SEP	(L) OCT	(M) NOV	(N) DEC	(O) AVERAGE MONTHLY BALANCES
1	CONTRIBUTED CAPITAL	91,445,258	91,445,258	91,445,258	91,206,967	91,206,967	91,206,967	91,206,967	91,206,967	91,206,967	91,206,967	91,206,967	149,582,173	149,582,173	100,242,758
2															
3	CURRENT YEAR CAPITAL CONTRIBUTIONS											58,375,206			4,490,400
4															
5	COMMON STOCK BALANCE	91,445,258	91,445,258	91,445,258	91,206,967	91,206,967	91,206,967	91,206,967	91,206,967	91,206,967	91,206,967	149,582,173	149,582,173	149,582,173	104,733,159
6	RETAINED EARNINGS -														
7	BEGINNING BALANCE	127,723,553	124,870,030	127,937,145	129,613,027	123,736,629	126,186,655	127,366,415	121,712,881	123,671,757	126,567,979	121,100,856	123,683,755	126,209,467	125,414,627
8	NET INCOME (2)	(892,764)	3,067,115	1,675,882	1,178,733	2,450,025	1,179,761	1,445,976	1,958,576	2,896,222	1,637,984	2,592,898	2,515,712	1,899,406	1,815,755
9	DIVIDENDS (3)	(6,970,759)			(7,098,909)			(7,143,291)			(7,148,888)		0	(7,168,522)	(2,733,105)
10	OTHER (4)	5,010,000	0	0	43,778	1	(1)	43,781	0		43,781	1		93,729	402,698
11	END OF MONTH BALANCE	124,870,030	127,937,145	129,613,027	123,736,629	126,186,655	127,366,415	121,712,881	123,671,757	126,567,979	121,100,856	123,683,755	126,209,467	121,033,074	124,899,975
12	OTHER COMPREHENSIVE INCOME	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	TOTAL ELECTRIC COMMON EQUITY	216,315,288	219,382,403	221,058,285	214,943,596	217,393,622	218,573,382	212,919,848	214,878,724	217,774,946	212,307,823	273,275,928	275,791,640	270,615,247	229,633,133

(1) Actual 2006 WIP D-3, PAGE 1 OF 1
(2) Net Income from Monthly F/S page 4
(3) Statement of Cash Flows - page 6 of monthly F/S
(4) Page 3 of Monthly F/S; Increase(Decrease) in Other Comp Income for the Month

14	Check (s/h zero)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Page 3 of monthly F/S	216,315,288	219,382,403	221,058,285	214,943,596	217,393,622	218,573,382	212,919,848	214,878,724	217,774,946	212,307,823	273,275,928	275,791,640	270,615,247	

Prepared By: kas
Reviewed By: pjb

Otter Tail Power Company
Adjustment To Calculate Deferred Income Taxes For
Land Portion Of Big Stone Capitalized Overhead Costs
North Dakota Jurisdiction
Actual Year 2007

Line No.	(A)	(B)	(C)	(D)
	System-Wide Rate Base Amounts			
1	NORTH DAKOTA ADJUSTMENT			
2		Adjustment To	Adjustment To	Adjustment To
3		12/31/2006	12/31/2007	Average Balances
4	Accumulated Deferred Income Taxes:			
5	Items South Dakota Flows Through			
6	Federal	0	0	0
7	Minnesota	0	0	0
8	North Dakota	0	0	0
9				
10	Subtotal	0	0	0
11				
12	Accumulated Deferred Income Taxes:			
13	All Other Accumulated Deferred Income Taxes	(1)	(2)	
14	Federal	62,079	49,994	56,036.26
15	Minnesota	0	0	0.00
16	North Dakota	7,309	5,885	6,596.67
17				
18	Subtotal	69,387	55,879	62,633
19				
20	Total Accumulated Deferred Income Tax	69,387	55,879	62,633
21				
22				

(1) 2006 Actual Year COSS W/P ND-1, Page 1 of 3

(2) Amounts At (1) Less Amounts At ND-1, Page 2 of 3

NOTE: Adjustment is a credit - input signs are opposite.

Prepared By: kas
Reviewed By: pjb

Otter Tail Power Company
Adjustment To Calculate Deferred Income Taxes For
Amortization Of Big Stone Capitalized Overhead Costs
North Dakota Jurisdiction
Actual Year 2007

Line	(A)	(B)
No.	NORTH DAKOTA ADJUSTMENT	Systemwide Operating Statement Amounts
1		
2		<u>Expense</u>
3	Deferred Income Taxes:	
4	Items South Dakota Flows Through	
5	Federal	0
6	Minnesota	0
7	North Dakota	0
8		
9	Subtotal	<u>0</u>
10		
11	Deferred Income Taxes:	
12	All Other Deferred Income Taxes	
13	Federal	(12,084.50) (1)
14	Minnesota	0.00 (1)
15	North Dakota	<u>(1,424.13) (1)</u>
16	Subtotal	(13,509)
17		
18	Total Deferred Income Tax	<u><u>(13,509)</u></u>
19		
20		
21	(1) ND-1, Page 3 Of 3	
22		

Prepared By: kas
Reviewed By: pjb

Otter Tail Power Company
Adjustment To Calculate Deferred
Income Taxes For Amortization Of Big Stone Capitalized Overhead Costs
North Dakota Jurisdiction
Actual Year 2007

Line No.	(A)	(B)	(C)	(D)
	FLOWBACK OF DEFERRED TAXES - NORTH DAKOTA			
1		Deferred Federal Tax		Deferred State Tax
2				Deferred Total Tax
3				
4	Required Decrease In ND Deferred Tax	(4,765) (3)	(1,419) (3)	(6,184) (1)
5	Estimated NEPIS Factor (NPISN Factor For ND)	39.43% (2)	99.64% (2)	N/A
6				
7	Systemwide Deferred Tax Decrease	(12,084)	(1,424)	(13,509)
8				
9				
10				

- (1) GLFire account 2575.3210 (FERC a/c 283.0) charges for the year 2007; '06 Balance less '07 Balance
(2) 2006 Actual Year COSS. Rounded To 4 Decimal Places To Emphasize That These Factors (NEPIS And NPISN Are Only An Estimate Of The Actual Year 2007 Factors. (page 16 a of the ND COSS
(3) Spread So That The Split For System-wide Deferred Tax Decrease Will Evenly Amortize The ADIT Balance At 12/31/06 Per ND-1, Page 1 Of 3. The Following Is A Reasonability Check

	12/31/2006				
	Balances				
Federal	62,079	/	12,084	=	5.1 YEARS
ND	7,309	/	1,424	=	5.1 YEARS

Note: A Gross Up Of Deferred Tax Expense Is Necessary Because We Don'T Jurisdictionalize Deferred Tax

Prepared by: kas
Reviewed by:

Otter Tail Power Company
Adjustment to Eliminate Wind Project Costs From Rate Bas
Actual Year 2007

Line No.	(A)	(B)	(C)	(D)	(E)
1	RATE BASE				
2	PLANT-IN -SERVICE				
3	Beginning-of-Year				
4	2007 Capitalized Costs - Production				
5	Acct 101			0	(1)
6	Acct 106			0	(1)
8	Total 2007 Capitalized Production Costs			0	
9					
10	Base/ Peak Split				
11	Base Demand	66.87% (2)		0	(3)
12	Peak Demand	33.13% (2)		0	(3)
13	Total Adjustments to Production Plant in Service			0	
14	End-of-Year				
15	2007 Capitalized Costs - Production				
16	Acct 101			1,024,097	(1)
17	Acct 106			65,000,000	(1)
18	Total 2007 Capitalized Production Costs			66,024,097	
20	Base/ Peak Split				
21	Base Demand	71.89% (2)		47,464,723	
22	Peak Demand	28.11% (2)		18,559,374	
23	Total Adjustments to Production Plant in Service			66,024,097	
24	Total Avg Adjustment to Production Plant - Base Demand			23,732,362	(3)
25	Total Avg Adjustment to Production Plant - Peak Demand			9,279,687	(3)
26	Total Adjustment to Plant in Service - Production			33,012,048	
27					
28	2007 Capitalized Costs - Transmission Beginning of Year			0	(1)
29	2008 Capitalized Costs - Transmission End of Year			0	(1)
30	Total Avg Adjustment to Plant in Service - Transmission			0	(3)
31	Total Avg Adjustment To Plant in Service			33,012,048	
32	ACCUMULATED DEPRECIATION				
33	Beginning-of-Year				
34	2007 Accumulated Depreciation - Production			0	(1)
35	Base/ Peak Split				
36	Base Demand	66.87%		0	
37	Peak Demand	33.13%		0	
38	Total Adjustments to Production A/D			0	
39	End-of-Year				
40	2007 Accumulated Depreciation - Production			0	(1)
41	Base/ Peak Split				
42	Base Demand	71.89%		0	
43	Peak Demand	28.11%		0	
44	Total Adjustments to Production A/D			0	
45					
46	Total Avg Adjustment to Production Plant A/D - Base Demand			0	(4)
47	Total Avg Adjustment to Production Plant A/D - Peak Demand			0	(4)
48	Total Adjustment to A/D - Production			0	
49	2006 Accumulated Depreciation - Transmission Beginning of Year			0	(1)
50	2007 Accumulated Depreciation - Transmission End of Year			0	(1)
51	Total Avg Adjustment to A/D - Transmission			0	(4)
52	Total Adjustment to Accumulated Depreciation			0	

- (1) From Accounting Department
(2) C-1; Page 1 of 3
(3) Adjustment found on Input Summary; A-Summary, Page 1 of 5
(4) Adjustment found on Input Summary; A-Summary, Page 2 of 5

Note: Adjustment is to eliminate costs related to wind projects as the revenue requirements for these projects are recovered through tariff riders

Prepared by: kas
Reviewed by:

Otter Tail Power Company
Adjustment to Eliminate Wind Project Costs From the Income Statement
Actual Year 2007

Line No.	(A)	(B)	(C)	(D)
1	OPERATING STATEMENT			
2	2007 Depreciation Expense - Production		0	(1)
3				
4	Base/ Peak Split			
5	Base Demand	71.89% (2)	0	(3)
6	Peak Demand	28.11% (2)	0	(3)
7	Total Adjustments to Production Plant in Service		0	
8				
9				
10	2007 Depreciation Expense - Transmission		0	(1); (3)
11				
12	Total Adjustment to Depreciation Expense		0	
13				
14				
15	(1) From Accounting Department			
16	(2) ND-4; Page 1 of 2			
17	(3) Adjustment found on Input Summary; B-Summary, Page 4 of 7			
18				
19				
20	Note: Adjustment is to eliminate costs related to wind projects as the revenue requirements for these projects are			
21	recovered through tariff riders.			