Phillip J. Zins

I graduated from Minnesota State University-Mankato in 1973 with a Bachelor of Science degree in Economics. In 1976, I graduated from Michigan State University with a Master of Arts degree in Economics.

I have been employed by the former Northern States Power Company (NSP) and Xcel Energy, for 25 years. I began my employment with NSP in 1983 as Administrator of Electric Rate Design and later that year was promoted to Manager of Electric Rate Design. In 1990, I was promoted to Manager of Pricing and Load Research and in 1991 to General Manager of Pricing and Sales Forecasting. Included in my responsibilities as General Manager, were Electric Pricing and Service Policy for Minnesota, North and South Dakota, Load Research, Sales Forecasting and Energy Supply Planning for all of NSP.

Effective with the merger of Northern States Power Company and New Century Energies in 2000, I became Manager Pricing and Planning for Xcel Energy. In this capacity, my primary responsibilities included Electric and Gas Pricing for Minnesota, North and South Dakota. In 2005, Xcel Energy's Gas Pricing function was reorganized under a separate Gas Pricing Manager. My current responsibility is electric utility pricing for Minnesota, North Dakota and South Dakota.

Before beginning my career with Xcel Energy, I was employed by the Minnesota Department of Public Service (DPS), which function is how part of the Department of Commerce. I was employed by the DPS from 1976 to 1983, during which time I moved from Public Utility Rate Analyst to Energy Section Supervisor.

During my employment with Xcel Energy and the Minnesota Department of Public Service, I have testified in numerous rate cases before the Minnesota, South Dakota and Colorado Public Utilities Commissions and the North Dakota Public Service Commission.

Proposed Class Cost of Service Study Results ($000)

Summary

UNADJUSTED	Total	Residential	Non-Demand	Demand	Street Ltg
Total Oper Revenues	167,714	65,649	11,874	88,367	1,825
Incr Late Pay & Misc Chrg	78	37	9	31	1
Revenue Reqt	167,636	65,611	11,865	88,336	1,824
Present Rates	147,179	57,724	10,436	77,139	1,881
Deficiency	20,535	7,925	1,438	11,228	(56)
Defic / Pres	14.0%	13.7%	13.8%	14.6%	-3.0%
Ratio: Class % / Total %	**1.00**	**0.98**	**0.99**	**1.04**	**-0.21**

ADJUSTED					
Total Oper Revenues	171,498	66,890	12,153	90,620	1,835
Incr Late Pay & Misc Chrg	78	37	9	31	1
Revenue Reqt	171,420	66,853	12,144	90,589	1,834
Present Rates	150,963	58,141	10,455	80,487	1,881
Deficiency	20,457	8,712	1,690	10,102	(46)
Defic / Adj Pres	13.6%	15.0%	16.2%	12.6%	-2.5%
Ratio: Class % / Total %	**1.00**	**1.11**	**1.19**	**0.93**	**-0.18**

PROPOSED					
Proposed Rates	167,636	65,968	11,988	87,799	1,880
Prop - Pres	20,457	8,245	1,552	10,660	(0)
Difference / Pres	13.9%	14.3%	14.9%	13.8%	0.0%
Ratio: Class % / Total %	**1.00**	**1.03**	**1.07**	**0.99**	**0.00**

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
Proposed Class Cost of Service Study

Case No. PU-07-______
Exhibit No. ______(PJZ-1
Schedule 2
Page 2 of 19

Rate Base

		Alloc	1=2+3+9	2	3=4+5	4	5=6 to 8	6	7	8	9
	Plant In Service		ND	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Transmiss	St Ltg
1	Production		356,704	123,135	231,750	23,900	207,850	191,905	15,945	0	1,819
2	Transmission		87,557	33,070	54,103	6,909	47,194	45,209	1,985	0	383
3	Distribution		124,202	71,349	48,965	9,452	39,513	38,181	1,332	0	3,888
4	General		14,538	5,820	8,563	1,030	7,533	7,040	493	0	156
5	Common		24,338	9,742	14,335	1,724	12,611	11,786	825	0	261
6	TBT Invest		0	0	0	0	0	0	0	0	0
7	Total		607,339	243,116	357,716	43,014	314,702	294,122	20,579	0	6,507
	Depreciation Reserve										
8	Production		234,339	81,342	151,737	15,521	136,216	125,749	10,467	0	1,260
9	Transmission		29,941	11,286	18,524	2,357	16,167	15,476	691	0	131
10	Distribution		48,239	27,305	18,674	3,616	15,057	14,554	503	0	2,259
11	General		6,955	2,784	4,096	493	3,604	3,368	236	0	75
12	Common		13,692	5,481	8,064	970	7,095	6,631	464	0	147
13	Total		333,166	128,198	201,096	22,957	178,138	165,778	12,361	0	3,872
14	**Net Plant In Service**		274,173	114,918	156,620	20,056	136,564	128,345	8,219	0	2,635
	Deductions										
15	Accum Defer Inc Tax		40,717	18,150	22,357	2,989	19,368	18,298	1,070	0	209
	Additions										
16	Constr Work In Progress		4,802	1,663	3,117	340	2,777	2,576	201	0	22
17	Fuel Inventory		2,358	828	1,516	152	1,364	1,259	105	0	14
18	Materials & Supplies		5,412	2,035	3,332	374	2,958	2,749	209	0	45
19	Prepayments		1,864	781	1,065	136	928	873	56	0	18
20	Non-Plant Assets & Liab		(6,928)	(2,999)	(3,827)	(542)	(3,285)	(3,061)	(224)	0	(102)
21	Working Cash		1,136	489	630	83	547	515	32	0	16
22	Total		8,644	2,798	5,833	543	5,290	4,910	380	0	13
23	**Rate Base**		242,100	99,565	140,096	17,611	122,486	114,957	7,529	0	2,439

Income Statement

		ND	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Transmiss	St Ltg
24A	**Tot Oper Rev - Pres**	186,704	71,881	112,706	13,124	99,582	92,912	6,670	0	2,117
24B	**Tot Oper Rev - Prop**	207,239	80,163	124,958	14,686	110,273	102,916	7,356	0	2,117
25	Oper & Maint	148,725	55,803	91,577	10,326	81,251	75,280	5,971	0	1,344
26	Book Depr + IRS Int	19,160	7,659	11,232	1,357	9,875	9,229	646	0	269
27	Payroll Tax	1,310	567	724	103	621	579	42	0	19
28	Real Est & Prop Tax	5,763	2,483	3,196	421	2,775	2,611	164	0	84
29	Deferred Inc Taxes	1,738	552	1,201	139	1,062	993	69	0	(14)
30A	Present Income Tax	214	473	(415)	32	(447)	(231)	(216)	0	157
30B	Proposed Income Tax	8,270	3,722	4,391	644	3,747	3,694	53	0	157
31	Allow Funds Dur Const	0	0	0	0	0	0	0	0	0
32A	**Present Return**	9,794	4,344	5,192	746	4,446	4,452	(7)	0	258
32B	**Proposed Return**	22,273	9,377	12,638	1,695	10,943	10,532	410	0	258
33A	**Pres Ret on Rt Base**	4.05%	4.36%	3.71%	4.24%	3.63%	3.87%	-0.09%	0.00%	10.59%
33B	**Prop Ret on Rt Base**	9.20%	9.42%	9.02%	9.63%	8.93%	9.16%	5.45%	0.00%	10.60%
34A	**Pres Ret on Common**	1.54%	2.15%	0.88%	1.91%	0.73%	1.20%	-6.45%	0.00%	14.18%
34B	**Prop Ret on Common**	11.49%	11.91%	11.15%	12.32%	10.98%	11.42%	4.25%	0.00%	14.19%

PRES vs Equal Rev Reqts

			1=2+3+9	2	3=4+5	4	5=6 to 8	6	7	8	9
	Total Retail Rev Reqt	Alloc	ND	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Transmiss	St Ltg
1	Equal Return On Rate Base		9.20%	9.20%	9.20%	9.20%	9.20%	9.20%	9.20%	9.20%	9.20%
2	Equalized Rev Reqt		167,636	65,611	100,201	11,865	88,336	82,146	6,190	(0)	1,824
3	Present Revenue		147,179	57,724	87,575	10,436	77,139	72,097	5,042	0	1,881
4	Revenue Deficiency		20,457	7,888	12,626	1,429	11,197	10,049	1,148	(0)	(56)
5	Deficiency / Present		13.90%	13.66%	14.42%	13.69%	14.51%	13.94%	22.76%	0.00%	-3.00%
6	Firmed Up Revenue		3,784	417	3,367	19	3,348	2,661	687	0	0
7	Interruptible Capacity Costs	D10C	3,784	1,242	2,533	279	2,253	2,083	170	0	10
8	Revenue Shift		0	824	(834)	261	(1,095)	(578)	(517)	0	10
9	Adj Equal Rev Reqt (Rows 2+7)		171,420	66,853	102,733	12,144	90,589	84,229	6,360	(0)	1,834
10	Adj Pres Rev (Rows 3+6)		150,963	58,141	90,942	10,455	80,487	74,758	5,729	0	1,881
11	Adj Revenue Deficiency		20,457	8,712	11,791	1,690	10,102	9,471	631	(0)	(46)
12	Adj Deficiency / Adj Present		13.55%	14.98%	12.97%	16.16%	12.55%	12.67%	11.01%	0.00%	-2.47%
	Customer Component										
13	Min Sys & Service Drop		11,705	8,958	1,771	1,167	603	578	26	0	976
14	Energy Services		5,435	4,271	1,141	734	406	401	5	0	23
15	Total Customer (Cusco)		17,141	13,230	2,912	1,902	1,010	979	31	0	1,000
16	Ave Monthly Customers		87,633	73,609	12,024	8,656	3,368	3,338	30	0	2,000
17	Svc Drop Reqt	$ / Mo / Cust	$11.13	$10.14	$12.27	$11.24	$14.93	$14.43	$69.92	$0.00	$40.68
18	Ener Svcs Reqt	$ / Mo / Cust	$5.17	$4.84	$7.91	$7.07	$10.06	$10.02	$14.68	$0.00	$0.97
19	Total Reqt	$ / Mo / Cust	$16.30	$14.98	$20.18	$18.31	$24.99	$24.44	$84.60	$0.00	$41.64
	Energy Component										
20	On Peak Rev Reqt		45,030	14,259	30,661	3,247	27,413	25,384	2,029	0	110
21	Off Peak Rev Reqt		38,235	14,942	22,906	2,121	20,786	19,107	1,679	0	387
22	Total Ener Rev Reqt		83,264	29,201	53,567	5,368	48,199	44,491	3,708	0	497
23	Annual Mwh Sales		2,217,924	782,202	1,417,004	135,756	1,281,248	1,177,078	104,171	0	18,717
24	On Pk Reqt	Mills / kWh	20.303	18.229	21.638	23.921	21.396	21.566	19.476	0.000	5.882
25	Off Pk Reqt	Mills / kWh	17.239	19.102	16.165	15.621	16.223	16.232	16.117	0.000	20.650
26	Total Reqt	Mills / kWh	37.542	37.331	37.803	39.542	37.619	37.798	35.593	0.000	26.532
	Demand Component										
27	Base Load Prod		21,889	7,678	14,081	1,412	12,668	11,693	976	0	131
28	Summer Peak Prod		15,565	4,702	10,863	1,186	9,677	8,932	745	0	0
29	Winter Peak Prod		5,250	2,123	3,073	348	2,724	2,533	191	0	55
30	Total Production		42,704	14,503	28,016	2,946	25,070	23,158	1,912	0	185
31	Transmission (Transco)		14,231	5,388	8,781	1,125	7,656	7,343	313	0	63
32	Primary Dist Subs		2,834	1,141	1,664	172	1,493	1,397	96	0	30
33	Prim Dist Lines		3,246	979	2,236	199	2,037	1,907	131	0	30
34	Second Dist. Trans		4,216	1,171	3,026	154	2,872	2,872	0	0	20
35	Total Distribution (Disco)		10,296	3,291	6,925	524	6,402	6,175	226	0	80
36	Total Demand Rev Reqt		67,231	23,181	43,722	4,595	39,127	36,676	2,451	0	328
37	Annual Billing kW		3,530,304	0	3,530,304	0	3,530,304	3,304,606	225,698	0	0
38	Base Rev Reqt	$ / kW	$0.00	$0.00	$3.99	$0.00	$3.59	$3.54	$4.32	$0.00	$0.00
39	Summer Rev Reqt	$ / kW	$0.00	$0.00	$3.08	$0.00	$2.74	$2.70	$3.30	$0.00	$0.00
40	Winter Rev Reqt	$ / kW	$0.00	$0.00	$0.87	$0.00	$0.77	$0.77	$0.85	$0.00	$0.00
41	Prod Rev Reqt	$ / kW	$0.00	$0.00	$7.94	$0.00	$7.10	$7.01	$8.47	$0.00	$0.00
42	Tran Rev Reqt	$ / kW	$0.00	$0.00	$2.49	$0.00	$2.17	$2.22	$1.39	$0.00	$0.00
43	Dist Rev Reqt	$ / kW	$0.00	$0.00	$1.96	$0.00	$1.81	$1.87	$1.00	$0.00	$0.00
44	Tot Dmd Rev Reqt		$0.00	$0.00	$12.38	$0.00	$11.08	$11.10	$10.86	$0.00	$0.00
45	Tot Dmd Rev Reqt	Mills / kWh	30.313	29.635	30.855	33.846	30.539	31.159	23.530	0.000	17.522
46	Summer Billing kW		1,222,164	0	1,222,164	0	1,222,164	1,142,641	79,523	0	0
47	Winter Billing kW		2,308,140	0	2,308,140	0	2,308,140	2,161,965	146,175	0	0
48	Tot Summer Reqt	$ / kW	$0.00	$0.00	$17.33	$0.00	$15.49	$15.45	$16.08	$0.00	$0.00
49	Tot Winter Reqt	$ / kW	$0.00	$0.00	$9.77	$0.00	$8.75	$8.80	$8.02	$0.00	$0.00
50	Energy + Production (Genco)		125,968	43,703	81,583	8,314	73,269	67,649	5,620	0	682

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
Proposed Class Cost of Service Study

PROP vs Equal Rev Reqts

			1=2+3+9	2	3=4+5	4	5=6 to 8	6	7	8	9
	Total Retail Rev Reqt	Alloc	ND	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Transmiss	St Ltg
1	Proposed Ret On Rt Base		9.20%	9.42%	9.02%	9.63%	8.93%	9.16%	5.45%	0.00%	10.60%
2	Equalized Rev Reqt		167,636	65,611	100,201	11,865	88,336	82,146	6,190	(0)	1,824
3	Proposed Revenue		167,636	65,968	99,787	11,988	87,799	82,074	5,725	(0)	1,880
4	Revenue Deficiency		0	(357)	413	(123)	537	72	465	(0)	(56)
5	Deficiency / Proposed		0.00%	-0.54%	0.41%	-1.03%	0.61%	0.09%	8.11%	0.00%	-2.98%
6	Firmed Up Revenue		3,784	417	3,367	19	3,348	2,661	687	0	0
7	Interruptible Capacity Costs	D10C	3,784	1,242	2,533	279	2,253	2,083	170	0	10
8	Revenue Shift		0	824	(834)	261	(1,095)	(578)	(517)	0	10
9	Adj Equal Rev (Rows 2+7)		171,420	66,853	102,733	12,144	90,589	84,229	6,360	(0)	1,834
10	Adj Prop Rev (Rows 3+6)		171,420	66,386	103,154	12,007	91,147	84,735	6,412	(0)	1,880
11	Adj Revenue Deficiency		0	467	(421)	137	(558)	(506)	(52)	(0)	(46)
12	Adj Deficiency / Adj Prop		0.00%	0.70%	-0.41%	1.14%	-0.61%	-0.60%	-0.81%	0.00%	-2.46%
	Customer Component										
13	Min Sys & Service Drop		11,705	6,993	3,888	1,040	2,848	2,739	109	0	824
14	Energy Services		5,435	4,297	1,115	739	376	372	4	0	23
15	Total Customer (Cusco)		17,141	11,291	5,003	1,779	3,224	3,111	113	0	847
16	Ave Monthly Customers		87,633	73,609	12,024	8,656	3,368	3,338	30	0	2,000
17	Svc Drop Reqt	$ / Mo / Cust	$11.13	$7.92	$26.95	$10.02	$70.46	$68.39	$297.22	$0.00	$34.33
18	Ener Svcs Reqt	$ / Mo / Cust	$5.17	$4.87	$7.73	$7.11	$9.31	$9.30	$11.24	$0.00	$0.95
19	Total Reqt	$ / Mo / Cust	$16.30	$12.78	$34.67	$17.13	$79.77	$77.69	$308.46	$0.00	$35.28
	Energy Component										
20	On Peak Rev Reqt		45,030	14,269	30,650	3,248	27,402	25,376	2,026	0	111
21	Off Peak Rev Reqt		38,235	14,944	22,904	2,122	20,781	19,105	1,677	0	387
22	Total Ener Rev Reqt		83,264	29,213	53,554	5,370	48,184	44,481	3,703	0	498
23	Annual Mwh Sales		2,217,924	782,202	1,417,004	135,756	1,281,248	1,177,078	104,171	0	18,717
24	On Pk Reqt	Mills / kWh	20.303	18.242	21.630	23.923	21.387	21.558	19.452	0.000	5.928
25	Off Pk Reqt	Mills / kWh	17.239	19.105	16.163	15.633	16.220	16.230	16.098	0.000	20.656
26	Total Reqt	Mills / kWh	37.542	37.347	37.794	39.557	37.607	37.789	35.549	0.000	26.584
	Demand Component										
27	Base Load Prod		21,889	8,477	13,217	1,543	11,674	10,997	677	0	195
28	Summer Peak Prod		15,565	5,386	10,112	1,184	8,927	8,352	575	0	67
29	Winter Peak Prod		5,250	2,155	3,039	367	2,671	2,515	156	0	57
30	Total Production		42,704	16,017	26,368	3,094	23,273	21,865	1,408	0	319
31	Transmission (Transco)		14,231	5,713	8,399	1,101	7,298	7,013	285	0	118
32	Primary Dist Subs		2,834	1,166	1,637	193	1,443	1,369	74	0	31
33	Prim Dist Lines		3,246	1,116	2,097	215	1,881	1,776	106	0	33
34	Second Dist, Trans		4,216	1,451	2,731	235	2,496	2,459	37	0	34
35	Total Distribution (Disco)		10,296	3,734	6,464	644	5,821	5,604	217	0	98
36	Total Demand Rev Reqt		67,231	25,464	41,231	4,839	36,392	34,482	1,909	0	536
37	Annual Billing kW		3,530,304	0	3,530,304	0	3,530,304	3,304,606	225,698	0	0
38	Base Rev Reqt	$ / kW	$0.00	$0.00	$3.74	$0.00	$3.31	$3.33	$3.00	$0.00	$0.00
39	Summer Rev Reqt	$ / kW	$0.00	$0.00	$2.86	$0.00	$2.53	$2.53	$2.55	$0.00	$0.00
40	Winter Rev Reqt	$ / kW	$0.00	$0.00	$0.86	$0.00	$0.76	$0.76	$0.69	$0.00	$0.00
41	Prod Rev Reqt	$ / kW	$0.00	$0.00	$7.47	$0.00	$6.59	$6.62	$6.24	$0.00	$0.00
42	Tran Rev Reqt	$ / kW	$0.00	$0.00	$2.38	$0.00	$2.07	$2.12	$1.26	$0.00	$0.00
43	Dist Rev Reqt	$ / kW	$0.00	$0.00	$1.83	$0.00	$1.65	$1.70	$0.96	$0.00	$0.00
44	Tot Dmd Rev Reqt		$0.00	$0.00	$11.68	$0.00	$10.31	$10.43	$8.46	$0.00	$0.00
45	Tot Dmd Rev Reqt	Mills / kWh	30.313	32.555	29.097	35.646	28.403	29.295	18.329	0.000	28.628
46	Summer Billing kW		1,222,164	0	1,222,164	0	1,222,164	1,142,641	79,523	0	0
47	Winter Billing kW		2,308,140	0	2,308,140	0	2,308,140	2,161,965	146,175	0	0
48	Tot Summer Reqt	$ / kW	$0.00	$0.00	$16.23	$0.00	$14.33	$14.46	$12.45	$0.00	$0.00
49	Tot Winter Reqt	$ / kW	$0.00	$0.00	$9.27	$0.00	$8.18	$8.31	$6.29	$0.00	$0.00
50	Energy + Production (Genco)		125,968	45,230	79,921	8,465	71,457	66,346	5,111	0	817
51	Prop Rev - Pres Rev (Pg 2)		20,457	8,245	12,212	1,552	10,660	9,977	683	(0)	(0)
52	Difference / Present		13.90%	14.28%	13.94%	14.88%	13.82%	13.84%	13.55%	#DIV/0!	-0.02%
53	Adj Prop - Adj Pres (Pg 2)		20,457	8,245	12,212	1,552	10,660	9,977	683	(0)	(0)
54	Difference / Adj Present		13.55%	14.18%	13.43%	14.85%	13.24%	13.35%	11.92%	#DIV/0!	-0.02%

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
Proposed Class Cost of Service Study

Case No. PU-07-______
Exhibit No. ______(PJZ-1
Schedule 2
Page 5 of 19

Original Plant in Service

		Alloc	1=2+3+9 ND	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5=6 to 8 Demand	6 Second	7 Primary	8 Transmiss	9 St Ltg
	Production										
1	Summer Peak	D10S	68,310	20,654	47,656	5,214	42,442	39,169	3,273	0	0
2	Winter Peak	D10W	23,044	9,323	13,482	1,533	11,949	11,109	840	0	239
3	Total Peak	[D10C]	91,354	29,977	61,138	6,746	54,391	50,278	4,113	0	239
4	Base Load	D8760	180,880	63,503	116,301	11,693	104,608	96,542	8,065	0	1,077
5	Nuclear Fuel	D8760	84,470	29,655	54,312	5,460	48,851	45,085	3,767	0	503
6	Total	33.56%	356,704	123,135	231,750	23,900	207,850	191,905	15,945	0	1,819
	Transmission										
7	Gen Step Up Base	D8760	1,067	375	686	69	617	569	48	0	6
8	Gen Step Up Peak	D10C	1,416	465	948	105	843	779	64	0	4
9	Total Gen Step Up		2,483	839	1,634	174	1,460	1,349	111	0	10
10	Bulk Transmission	D10T	85,060	32,231	52,456	6,736	45,720	43,853	1,867	0	373
11	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign	14	0	14	0	14	8	6	0	0
13	Total		87,557	33,070	54,103	6,909	47,194	45,209	1,985	0	383
	Distribution:										
	Substations										
14	Generat Step Up	STRATH	291	101	189	19	169	156	13	0	1
15	Bulk Transmission	D10T	130	49	80	10	70	67	3	0	1
16	Distrib Function	D60Sub	17,218	6,934	10,104	1,044	9,060	8,478	581	0	180
17	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0
18	Total		17,639	7,084	10,373	1,074	9,299	8,702	597	0	182
	Overhead Lines										
19	Primary Capacity	D61PS	9,712	2,934	6,687	595	6,092	5,700	391	0	91
20	Primary Customer	C61PS	6,058	5,198	854	614	239	237	2	0	6
21	Total Primary		15,770	8,132	7,541	1,210	6,331	5,937	394	0	97
22	Second Capacity	D62SecL	3,831	1,037	2,774	148	2,626	2,626	0	0	20
23	Second Customer	C62Sec	3,812	3,272	536	387	149	149	0	0	4
24	Total Secondary		7,643	4,309	3,310	535	2,775	2,775	0	0	24
25	Street Lighting	DASL	1,643	0	0	0	0	0	0	0	1,643
26	Total		25,056	12,441	10,850	1,745	9,106	8,712	394	0	1,764
	Underground Lines										
27	Primary Capacity	D61PS	4,120	1,245	2,837	253	2,584	2,418	166	0	39
28	Primary Customer	C61PS	19,809	16,997	2,791	2,009	782	775	7	0	21
29	Total Primary		23,929	18,242	5,628	2,262	3,366	3,193	173	0	59
30	Second Capacity	D62SecL	9,811	2,656	7,104	379	6,724	6,724	0	0	51
31	Second Customer	C62Sec	10,770	9,245	1,514	1,093	421	421	0	0	11
32	Total Secondary		20,581	11,901	8,618	1,472	7,146	7,146	0	0	62
33	Total		44,510	30,143	14,246	3,734	10,512	10,339	173	0	121
	Line Transformers										
34	Primary	D61PS	874	264	602	54	548	513	35	0	8
35	Second Capacity	D62SecL	9,048	2,450	6,551	350	6,201	6,201	0	0	47
36	Second Customer	C62Sec	6,392	5,487	899	649	250	250	0	0	7
37	Total		16,314	8,201	8,052	1,052	7,000	6,964	35	0	62
	Services										
38	Second Capacity	D62NLL	3,172	1,124	2,048	48	2,000	2,000	0	0	0
39	Second Customer	C62NL	8,435	7,978	457	330	127	127	0	0	0
40	Total		11,607	9,102	2,505	378	2,128	2,128	0	0	0
41	Meters	C12WM	7,322	4,379	2,939	1,469	1,469	1,336	133	0	4
42	Street Lighting	Dir Assign	1,754	0	0	0	0	0	0	0	1,754
43	**Total Distribution**		124,202	71,349	48,965	9,452	39,513	38,181	1,332	0	3,888
44	**General Plant**	PTD	14,538	5,820	8,563	1,030	7,533	7,040	493	0	156
45	**Electric Common**	PTD	24,338	9,742	14,335	1,724	12,611	11,786	825	0	261
46	Prelim Elec Plant		607,339	243,116	357,716	43,014	314,702	294,122	20,579	0	6,507
47	TBT Investment	NEPIS	0	0	0	0	0	0	0	0	0
48	**Elec Plant in Serv**		607,339	243,116	357,716	43,014	314,702	294,122	20,579	0	6,507

Accum Deprec; Net Plant

			1=2+3+9	2	3=4+5	4	5=6 to 8	6	7	8	9
	Production	**Alloc**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Transmiss**	**St Ltg**
1	Peaking Plant	D10C	40,494	13,288	27,100	2,990	24,110	22,286	1,823	0	106
2	Nuclear Fuel	D8760	76,688	26,923	49,308	4,957	44,351	40,931	3,420	0	457
3	Base Load	D8760	117,157	41,131	75,329	7,574	67,755	62,531	5,224	0	697
4	Total		234,339	81,342	151,737	15,521	136,216	125,749	10,467	0	1,260
	Transmission										
5	Gen Step Up Base	D8760	609	214	392	39	352	325	27	0	4
6	Gen Step Up Peak	D10C	808	265	541	60	481	445	36	0	2
7	Total Gen Step Up		1,417	479	932	99	833	770	64	0	6
8	Bulk Transmission	D10T	28,520	10,807	17,588	2,258	15,330	14,704	626	0	125
9	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	4	0	4	0	4	2	2	0	0
11	Total		29,941	11,286	18,524	2,357	16,167	15,476	691	0	131
	Distribution										
12	Generat Step Up	STRATH	108	37	70	7	63	58	5	0	1
13	Bulk Transmission	D10T	50	19	31	4	27	26	1	0	0
14	Distrib Function	D60Sub	6,380	2,569	3,744	387	3,357	3,142	215	0	67
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0
16	Total Substations		6,538	2,626	3,845	398	3,447	3,225	221	0	68
17	Overhead Lines	POL	9,529	4,731	4,126	664	3,463	3,313	150	0	671
18	Underground	PUL	16,898	11,444	5,408	1,418	3,991	3,925	66	0	46
19	Line Transformers	P68	6,400	3,217	3,159	413	2,746	2,732	14	0	24
20	Services	P69	4,553	3,570	983	148	835	835	0	0	0
21	Meters	C12WM	2,872	1,718	1,153	576	576	524	52	0	2
22	Street Lighting	P73	1,449	0	0	0	0	0	0	0	1,449
23	Total		48,239	27,305	18,674	3,616	15,057	14,554	503	0	2,259
24	**General Plant**	PTD	6,955	2,784	4,096	493	3,604	3,368	236	0	75
25	**Electric Common**	PTD	13,692	5,481	8,064	970	7,095	6,631	464	0	147
26	**Total Accum Depr**		333,166	128,198	201,096	22,957	178,138	165,778	12,361	0	3,872
27	**Net Elec Plant**		274,173	114,918	156,620	20,056	136,564	128,345	8,219	0	2,635

Subtractions: Accum Defer Inc Tax

			ND	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Transmiss	St Ltg
	Production										
28	Peaking Plant	D10C	5,814	1,908	3,891	429	3,462	3,200	262	0	15
29	Base Load	D8760	8,873	3,115	5,705	574	5,131	4,736	396	0	53
30	Nuclear Fuel	D8760	(67)	(24)	(43)	(4)	(39)	(36)	(3)	0	(0)
31	Total		14,620	4,999	9,553	999	8,554	7,900	654	0	68
	Transmission										
32	Gen Step Up Base	D8760	129	45	83	8	75	69	6	0	1
33	Gen Step Up Peak	D10C	172	56	115	13	102	95	8	0	0
34	Total Gen Step Up		301	102	198	21	177	164	13	0	1
35	Bulk Transmission	D10T	8,996	3,409	5,548	712	4,835	4,638	197	0	39
36	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0
37	Direct Assign	Dir Assign	1	0	1	0	1	1	0	0	0
38	Total		9,298	3,510	5,747	733	5,013	4,802	211	0	41
	Distribution										
39	Generat Step Up	STRATH	48	17	31	3	28	26	2	0	0
40	Bulk Transmission	D10T	23	9	14	2	12	12	1	0	0
41	Distrib Function	D60Sub	2,100	846	1,232	127	1,105	1,034	71	0	22
42	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0
43	Total Substations		2,171	871	1,278	132	1,145	1,072	74	0	22
44	Overhead Lines	POL	3,367	1,672	1,458	234	1,224	1,171	53	0	237
45	Underground	PUL	5,551	3,759	1,776	466	1,311	1,289	22	0	15
46	Line Transformers	P68	2,464	1,239	1,216	159	1,057	1,052	5	0	9
47	Services	P69	1,679	1,317	362	55	308	308	0	0	0
48	Meters	C12WM	807	483	324	162	162	147	15	0	0
49	Street Lighting	P73	(184)	0	0	0	0	0	0	0	(184)
50	Total		15,855	9,340	6,415	1,208	5,207	5,039	168	0	100
51	**General Plant**	PTD	1,370	548	807	97	710	663	46	0	15
52	**Electric Common**	PTD	1,937	775	1,141	137	1,004	938	66	0	21
53	**Total Deferred Tax**		43,080	19,173	23,662	3,174	20,488	19,342	1,146	0	244
54	TBT Acc Def Tax	NEPIS	0	0	0	0	0	0	0	0	0
55	Non-Plant Related	LABOR	(2,363)	(1,023)	(1,305)	(185)	(1,120)	(1,044)	(76)	0	(35)
56	**Accum Def W/(Adj**		40,717	18,150	22,357	2,989	19,368	18,298	1,070	0	209

Additions: CWIP, Etc; Rate Base

			1=2+3+9	2	3=4+5	4	5=6 to 8	6	7	8	9
	CWIP										
	Production	**Alloc**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Transmiss**	**St Ltg**
1	Peaking Plant	D10C	2,263	742	1,514	167	1,347	1,245	102	0	6
2	Base Load	D8760	1,182	415	760	76	684	631	53	0	7
3	Nuclear Fuel	D8760	699	246	450	45	405	373	31	0	4
4	Total		4,144	1,403	2,724	289	2,435	2,250	186	0	17
	Transmission										
5	Gen Step Up Base	D8760	1	0	1	0	1	1	0	0	0
6	Gen Step Up Peak	D10C	2	1	1	0	1	1	0	0	0
7	Total Gen Step Up		3	1	2	0	2	2	0	0	0
8	Bulk Transmission	D10T	521	197	321	41	280	268	11	0	2
9	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0
11	Total		524	198	323	41	282	270	12	0	2
	Distribution										
12	Generat Step Up	STRATH	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub	1	0	0	0	0	0	0	0	0
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0
16	Total Substations		1	0	1	0	0	0	0	0	0
17	Overhead Lines	POL	9	5	4	1	3	3	0	0	1
18	Underground	PUL	16	11	5	1	4	4	0	0	0
19	Line Transformers	P68	6	3	3	0	3	3	0	0	0
20	Services	P69	4	4	1	0	1	1	0	0	0
21	Meters	C12WM	3	2	1	1	1	1	0	0	0
22	Street Lighting	P73	1	0	0	0	0	0	0	0	1
23	Total		40	24	15	3	12	11	0	0	1
24	**General Plant**	PTD	53	21	31	4	27	25	2	0	1
25	**Electric Common**	PTD	41	16	24	3	21	20	1	0	0
26	**Total CWIP**		4,802	1,663	3,117	340	2,777	2,576	201	0	22
27	Fuel Inventory	E8760	2,358	828	1,516	152	1,364	1,259	105	0	14
	Materials & Supplies										
28	Production	P10	4,283	1,478	2,783	287	2,496	2,304	191	0	22
29	Trans & Distr	TD	1,129	557	550	87	462	445	18	0	23
30	Total		5,412	2,035	3,332	374	2,958	2,749	209	0	45
	Prepayments										
31	Miscellaneous	NEPIS	1,864	781	1,065	136	928	873	56	0	18
32	Total		1,864	781	1,065	136	928	873	56	0	18
33	Non-Plant Assets & Liab	LABOR	(6,928)	(2,999)	(3,827)	(542)	(3,285)	(3,061)	(224)	0	(102)
34	Working Cash	PT0	1,136	489	630	83	547	515	32	0	16
35	**Total Additions**		8,644	2,798	5,833	543	5,290	4,910	380	0	13
36	**Total Rate Base**		242,100	99,565	140,096	17,611	122,486	114,957	7,529	0	2,439
37	**Common Rate Base (@ 51.77%)**		125,335	51,545	72,528	9,117	63,411	59,513	3,898	0	1,263

Operating Rev (Cal Month)

Line	Description	Alloc	1=2+3+9 ND	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5=6 to 8 Demand	6 Second	7 Primary	8 Transmiss	9 St Ltg
	Retail Revenue										
1	Present Rate Revenue	R01; (calc)	147,179	57,724	87,575	10,436	77,139	72,097	5,042	0	1,881
2	Proposed Rate Revenue	PROREV; (calc)	167,636	65,968	99,787	11,988	87,799	82,074	5,725	0	1,880
	Other Retail Revenue										
3	Interdepartmental	R01; R02	0	0	0	0	0	0	0	0	0
4	Gross Earnings Tax	R01; R02	0	0	0	0	0	0	0	0	0
6	CIP Adjustment to Program Costs	D62E38	0	0	0	0	0	0	0	0	0
7	**Tot Other Retail Rev**		0	0	0	0	0	0	0	0	0
	Other Operating Revenue										
8	Interchg Prod Capacity	P10	8,994	3,105	5,843	603	5,241	4,839	402	0	46
9	Interchg Prod Energy	E8760	11,623	4,081	7,473	751	6,722	6,204	518	0	69
10	Interchg Tr Bulk Supply	D10T	2,031	770	1,252	161	1,092	1,047	45	0	9
11	Dist Int Sales; Oth Serv	E8760	0	0	0	0	0	0	0	0	0
12	Dist Overhd Line Rent	POL	251	125	109	17	91	87	4	0	18
13	Connection Charges	C11	173	145	24	17	7	7	0	0	4
14	Sales For Resale	E8760	12,380	4,346	7,960	800	7,160	6,608	552	0	74
15	Joint Op Agree-Other PSCo Rev	D10T	(116)	(44)	(72)	(9)	(62)	(60)	(3)	0	(1)
16	Production Assoc'd Rev	E8760	375	132	241	24	217	200	17	0	2
17	Misc Ancillary Trans Rev	D10T	3,008	1,140	1,855	238	1,617	1,551	66	0	13
18	MISO	D10T	241	91	149	19	130	124	5	0	1
19	Other	D10T	320	121	197	25	172	165	7	0	1
20	Late Pay Chg - Pres	R16C; R02	245	146	99	41	58	44	14	0	0
21	**Tot Other Op - Pres**		39,525	14,157	25,131	2,689	22,443	20,815	1,627	0	237
22	Windsource Revenues	Dir Assign	0	0	0	0	0	0	0	0	0
23	Incr Misc Serv - Prop	R01,	43.7225	17	26	3	23	21	1	0	1
24	Incr Late Pay - Prop	(R16C); R02	34.0528	20	14	6	8	6	2	0	0
25	**Tot Other Op - Prop**		39,603	14,195	25,171	2,697	22,473	20,842	1,631	0	237
26	**Tot Oper Rev - Pres**		186,704	71,881	112,706	13,124	99,582	92,912	6,670	0	2,117
27	**Tot Oper Rev - Prop**		207,239	80,163	124,958	14,686	110,273	102,916	7,356	0	2,117

Operating & Maint (Pg 1 of 2)

Line	Description	Alloc	ND	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Transmiss	St Ltg
	Production Expen										
28	**Fuel**	E8760	35,469	12,452	22,805	2,293	20,512	18,931	1,582	0	211
	Purchased Power										
29	Purchases: Cap Peak	D10C	5,554	1,822	3,717	410	3,307	3,057	250	0	15
30	Purchases: Cap Base	D8760	4,183	1,468	2,689	270	2,419	2,232	186	0	25
31	Purchases: Demand		9,737	3,291	6,406	681	5,726	5,289	437	0	39
32	Purchases: Other Energy	E8760	43,614	15,312	28,043	2,819	25,223	23,278	1,945	0	260
33	Tot Non-Assoc Purch		53,351	18,603	34,449	3,500	30,949	28,568	2,381	0	299
34	Interchg Agr Capacity	P10	2,290	791	1,488	153	1,334	1,232	102	0	12
35	Interchg Agr Energy	E8760	1,340	470	862	87	775	715	60	0	8
36	Tot Wis Interchg Purch		3,630	1,261	2,349	240	2,109	1,947	162	0	20
37	**Tot Purchased Power**		56,981	19,864	36,798	3,740	33,058	30,515	2,543	0	319
	Other Production										
38	Capacity Peaking	D10C	3,953	1,297	2,646	292	2,354	2,176	178	0	10
39	Capacity Baseload	D8760	2,977	1,045	1,914	192	1,721	1,589	133	0	18
40	Total Capacity		6,930	2,342	4,559	484	4,075	3,764	311	0	28
41	Energy	E8760	20,127	7,066	12,941	1,301	11,640	10,743	897	0	120
42	Total Other Produc		27,057	9,408	17,500	1,785	15,715	14,507	1,208	0	148
43	**Total Production**		119,506	41,724	77,104	7,818	69,286	63,953	5,333	0	678
44	**Transmission Exp**	D10T	7,992	3,028	4,928	633	4,296	4,120	175	0	35

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
Proposed Class Cost of Service Study

Case No. PU-07-______
Exhibit No. ______(PJZ-1
Schedule 2
Page 9 of 19

Operating & Maint (Pg 2 of 2)

			1=2+3+9	2	3=4+5	4	5=6 to 8	6	7	8	9
	Distribution Expen	**Alloc**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Transmiss**	**St Ltg**
1	Supervision & Eng'rg	ZDTS	423	229	172	35	138	132	6	0	22
2	Load Dispatching	D10T	247	94	153	20	133	128	5	0	1
3	Substations	P61	324	130	191	20	171	160	11	0	3
4	Overhead Lines	POL	2,065	1,026	894	144	751	718	32	0	145
5	Underground Lines	PUL	1,276	864	408	107	301	296	5	0	3
6	Line Transformers	P68	14	7	7	1	6	6	0	0	0
7	Meters	C12WM	179	107	72	36	36	33	3	0	0
8	Customer Install'n	OXDTS	42	21	17	3	13	13	1	0	4
9	Street Lighting	Dir Assign	219	0	0	0	0	0	0	0	219
10	Miscellaneous	OXDTS	731	376	292	55	237	227	10	0	63
11	Rents (Pole Attachmts)	POL	134	66	58	9	49	47	2	0	9
12	**Total Distribution**		5,655	2,920	2,264	429	1,835	1,759	75	0	471
13	**Customer Accounting**	C11WA	4,343	3,402	925	595	331	326	4	0	15
14	**Econ Development**	D100E0	2	1	1	0	1	1	0	0	0
	Admin & General										
15	Salaries	LABOR	2,885	1,249	1,594	226	1,368	1,275	93	0	42
16	Office Supplies	OXTS	2,784	1,045	1,714	193	1,521	1,409	112	0	25
17	Admin Transfer Credit	OXTS	(769)	(289)	(474)	(53)	(420)	(389)	(31)	0	(7)
18	Outside Services	LABOR	798	346	441	62	378	353	26	0	12
19	Property Insurance	NEPIS	315	132	180	23	157	147	9	0	3
20	Pensions & Benefits	LABOR	2,613	1,131	1,443	205	1,239	1,154	84	0	38
21	Injuries & Claims	LABOR	674	292	372	53	320	298	22	0	10
22	Regulatory Exp	R01; R02	70	28	42	5	37	34	2	0	1
23	General Advertising	OXTS	13	5	8	1	7	7	1	0	0
24	Contributions	OXTS	86	32	53	6	47	44	3	0	1
25	Misc General Exp	OXTS	234	88	144	16	128	118	9	0	2
26	Rents	OXTS	672	252	414	47	367	340	27	0	6
27	Maint of General Plant	OXTS	24	9	15	2	13	12	1	0	0
28	Total		10,399	4,319	5,946	785	5,161	4,802	359	0	134
	Cust Service & Info										
29	Cust Assist Exp - Non-CIP	C11P10	193	114	76	16	60	56	4	0	3
30	CIP Total	D62E38	38	14	24	3	21	20	1	0	0
31	Instructional Advertising	C11P10	138	82	54	11	43	40	3	0	2
32	Total		369	210	154	30	124	115	9	0	5
33	Amortizations	LABOR	460	199	254	36	218	203	15	0	7
34	**Total O&M Expense**		148,725	55,803	91,577	10,326	81,251	75,280	5,971	0	1,344

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
Proposed Class Cost of Service Study

Case No. PU-07-______
Exhibit No. ______(PJZ-1
Schedule 2

Book Depreciation

			1=2+3+9	2	3=4+5	4	5=6 to 8	6	7	8	9
	Production	**Alloc**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Transmiss**	**St Ltg**
1	Peaking Plant	D10C	3,212	1,054	2,150	237	1,912	1,768	145	0	8
2	Base Load	D8760	7,108	2,495	4,570	459	4,111	3,794	317	0	42
3	Total		10,320	3,549	6,720	697	6,023	5,562	462	0	51
	Transmission										
4	Gen Step Up Base	D8760	28	10	18	2	16	15	1	0	0
5	Gen Step Up Peak	D10C	37	12	25	3	22	20	2	0	0
6	Total Gen Step Up		65	22	43	5	38	35	3	0	0
7	Bulk Transmission	D10T	2,267	859	1,398	180	1,219	1,169	50	0	10
8	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0
9	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0
10	Total		2,332	881	1,441	184	1,257	1,204	53	0	10
	Distribution										
11	Generat Step Up	STRATH	8	3	5	1	5	4	0	0	0
12	Bulk Transmission	D10T	4	2	2	0	2	2	0	0	0
13	Distrib Function	D60Sub	477	192	280	29	251	235	16	0	5
14	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0
15	Total Substations		489	196	288	30	258	241	17	0	5
16	Overhead Lines	POL	722	359	313	50	262	251	11	0	51
17	Underground	PUL	1,282	868	410	108	303	298	5	0	3
18	Line Transformers	P68	528	265	261	34	227	225	1	0	2
19	Services	P69	375	294	81	12	69	69	0	0	0
20	Meters	C12WM	237	142	95	48	48	43	4	0	0
21	Street Lighting	P73	117	0	0	0	0	0	0	0	117
22	Total		3,750	2,124	1,447	281	1,166	1,127	38	0	179
23	**General Plant**	PTD	749	300	441	53	388	363	25	0	8
24	**Electric Common**	PTD	2,009	804	1,183	142	1,041	973	68	0	22
25	**Total Book Deprec**		19,160	7,659	11,232	1,357	9,875	9,229	646	0	269

Real Estate & Property Tax

			ND	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Transmiss	St Ltg
	Production										
26	Peaking Plant	D10C	632	207	423	47	376	348	28	0	2
27	Base Load	D8760	1,809	635	1,163	117	1,046	966	81	0	11
28	Total		2,441	842	1,586	164	1,422	1,313	109	0	12
	Transmission										
29	Gen Step Up Base	D8760	53	19	34	3	31	28	2	0	0
30	Gen Step Up Peak	D10C	186	61	124	14	111	102	8	0	0
31	Total Gen Step Up		239	80	159	17	141	131	11	0	1
32	Bulk Transmission	D10T	838	318	517	66	450	432	18	0	4
33	Distrib Function	D60Sub	1	0	1	0	1	0	0	0	0
34	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0
35	Total		1,078	398	676	84	592	563	29	0	4
	Distribution										
36	Generat Step Up	STRATH	0	0	0	0	0	0	0	0	0
37	Bulk Transmission	D10T	36	14	22	3	19	19	1	0	0
38	Distrib Function	D60Sub	366	147	215	22	193	180	12	0	4
39	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0
40	Total Substations		402	161	237	25	212	199	13	0	4
41	Overhead Lines	POL	417	207	181	29	152	145	7	0	29
42	Underground	PUL	627	425	201	53	148	146	2	0	2
43	Line Transformers	P68	428	215	211	28	184	183	1	0	2
44	Services	P69	172	135	37	6	32	32	0	0	0
45	Meters	C12WM	168	100	67	34	34	31	3	0	0
46	Street Lighting	P73	30	0	0	0	0	0	0	0	30
47	Total		2,244	1,243	934	174	760	734	26	0	67
48	**General Plant**	PTD	0	0	0	0	0	0	0	0	0
49	**Electric Common**	PTD	0	0	0	0	0	0	0	0	0
50	**Tot Rl Est & Pr Tax**		5,763	2,483	3,196	421	2,775	2,611	164	0	84
51	Gross Earnings Tax	R01; R02	0	0	0	0	0	0	0	0	0
52	Payroll Taxes	LABOR	1,310	567	724	103	621	579	42	0	19
53	**Tot Non-Inc Taxes**		7,073	3,050	3,920	523	3,396	3,190	207	0	103

Provision For Defer Inc Tax

		Alloc	1=2+3+9 ND	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5=6 to 8 Demand	6 Second	7 Primary	8 Transmiss	9 St Ltg
	Production										
1	Peaking Plant	D10C	1,214	398	812	90	723	668	55	0	3
2	Nuclear Fuel	D8760	78	27	50	5	45	42	3	0	0
3	Base Load	D8760	154	54	99	10	89	82	7	0	1
4	Total		1,446	480	962	105	857	792	65	0	5
	Transmission										
5	Gen Step Up Base	D8760	(6)	(2)	(4)	(0)	(3)	(3)	(0)	0	(0)
6	Gen Step Up Peak	D10C	(9)	(3)	(6)	(1)	(5)	(5)	(0)	0	(0)
7	Total Gen Step Up		(15)	(5)	(10)	(1)	(9)	(8)	(1)	0	(0)
8	Bulk Transmission	D10T	957	363	590	76	514	493	21	0	4
9	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0
11	Total		942	358	580	75	506	485	20	0	4
	Distribution										
12	Generat Step Up	STRATH	1	0	1	0	1	1	0	0	0
13	Bulk Transmission	D10T	7	3	4	1	4	4	0	0	0
14	Distrib Function	D60Sub	(13)	(5)	(8)	(1)	(7)	(6)	(0)	0	(0)
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0
16	Total Substations		(5)	(2)	(3)	(0)	(2)	(2)	(0)	0	(0)
17	Overhead Lines	POL	(24)	(12)	(10)	(2)	(9)	(8)	(0)	0	(2)
18	Underground	PUL	31	21	10	3	7	7	0	0	0
19	Line Transformers	P68	(122)	(61)	(60)	(8)	(52)	(52)	(0)	0	(0)
20	Services	P69	(56)	(44)	(12)	(2)	(10)	(10)	0	0	0
21	Meters	C12WM	11	7	4	2	2	2	0	0	0
22	Street Lighting	P73	(16)	0	0	0	0	0	0	0	(16)
23	Total		(181)	(92)	(71)	(7)	(64)	(64)	(1)	0	(18)
24	**General Plant**	PTD	76	30	45	5	39	37	3	0	1
25	**Electric Common**	PTD	(188)	(75)	(111)	(13)	(97)	(91)	(6)	0	(2)
26	**TBT Defer Inc Tax**	NEPIS	0	0	0	0	0	0	0	0	0
27	**Non - Plant Related**	LABOR	(93)	(40)	(51)	(7)	(44)	(41)	(3)	0	(1)
28	**Tot Prov For Defer**		2,002	660	1,354	157	1,196	1,118	78	0	(12)

Inv Tax Credit; Total Oper Exp

		Alloc	ND	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Transmiss	St Ltg
	Production										
29	Peaking Plant	D10C	(38)	(12)	(25)	(3)	(23)	(21)	(2)	0	(0)
30	Base Load	D8760	(131)	(46)	(84)	(8)	(76)	(70)	(6)	0	(1)
31	Total		(169)	(58)	(110)	(11)	(98)	(91)	(8)	0	(1)
	Transmission										
32	Bulk Transmission	D10T	(36)	(14)	(22)	(3)	(19)	(19)	(1)	0	(0)
33	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0
34	Total		(36)	(14)	(22)	(3)	(19)	(19)	(1)	0	(0)
	Distribution										
35	Overhead Lines	POL	(18)	(9)	(8)	(1)	(7)	(6)	(0)	0	(1)
36	Underground	PUL	(40)	(27)	(13)	(3)	(9)	(9)	(0)	0	(0)
37	Total		(58)	(36)	(21)	(5)	(16)	(16)	(0)	0	(1)
38	**General Plant**	PTD	0	0	0	0	0	0	0	0	0
39	**Electric Common**	PTD	(1)	(0)	(1)	(0)	(1)	(0)	(0)	0	(0)
40	**Net Inv Tax Credit**		(264)	(109)	(153)	(19)	(134)	(125)	(9)	0	(2)
41	**Total Operating Exp**		176,696	67,064	107,930	12,346	95,584	88,691	6,893	0	1,702
42A	**Pres Op Inc Before Inc Tax**		10,009	4,816	4,777	778	3,998	4,221	(223)	0	416
42B	**Prop Op Inc Before Inc Tax**		30,543	13,098	17,029	2,340	14,689	14,226	463	0	416

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
Proposed Class Cost of Service Study

Case No. PU-07-______
Exhibit No. ______(PJZ-1
Schedule 2

Tax Deprec; Inc Tax & Return

		Alloc	1=2+3+9 ND	2 Res	3=4+5 C&I Tot	4 Sm Non-D	5=6 to 8 Demand	6 Second	7 Primary	8 Transmiss	9 St Ltg
	Production										
1	Peaking Plant	D10C	7,291	2,392	4,879	538	4,341	4,013	328	0	19
2	Nuclear Fuel	D8760	4,676	1,642	3,007	302	2,704	2,496	209	0	28
3	Base Load	D8760	7,795	2,737	5,012	504	4,508	4,160	348	0	46
4	Total		19,762	6,771	12,898	1,345	11,553	10,669	884	0	93
	Transmission										
5	Gen Step Up Base	D8760	12	4	8	1	7	6	1	0	0
6	Gen Step Up Peak	D10C	16	5	11	1	10	9	1	0	0
7	Total Gen Step Up		28	9	18	2	16	15	1	0	0
8	Bulk Transmission	D10T	4,777	1,810	2,946	378	2,568	2,463	105	0	21
9	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0
11	Total		4,805	1,820	2,964	380	2,584	2,478	106	0	21
	Distribution										
12	Generat Step Up	STRATH	10	3	6	1	6	5	0	0	0
13	Bulk Transmission	D10T	26	10	16	2	14	13	1	0	0
14	Distrib Function	D60Sub	446	180	262	27	235	220	15	0	5
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0
16	Total Substations		482	193	284	30	254	238	16	0	5
17	Overhead Lines	POL	614	305	266	43	223	213	10	0	43
18	Underground	PUL	1,408	954	451	118	333	327	5	0	4
19	Line Transformers	P68	262	132	129	17	112	112	1	0	1
20	Services	P69	367	288	79	12	67	67	0	0	0
21	Meters	C12WM	202	121	81	41	41	37	4	0	0
22	Street Lighting	P73	57	0	0	0	0	0	0	0	57
23	Total		3,392	1,992	1,290	260	1,030	995	35	0	110
24	**General Plant**	PTD	1,116	447	657	79	578	540	38	0	12
25	**Electric Common**	PTD	1,531	613	902	108	793	741	52	0	16
26	**TBT Defer Inc Tax**	NEPIS	(1)	(0)	(1)	(0)	(0)	(0)	(0)	0	(0)
27	**Total Tax Deprec**		30,605	11,641	18,711	2,172	16,539	15,423	1,116	0	253
28	Interest Expense		7,868	3,236	4,553	572	3,981	3,736	245	0	79
29	Other Tax Timing Differ		64	24	39	5	34	33	1	0	0
30	Total Tax Deductions		38,537	14,901	23,304	2,750	20,554	19,192	1,362	0	332
	Inc Tax Additions										
31	Book Depreciation		19,160	7,659	11,232	1,357	9,875	9,229	646	0	269
32	Deferred Inc Tax & ITC		1,738	552	1,201	139	1,062	993	69	0	(14)
33	Nuclear Fuel Book Burn	E8760	4,012	1,409	2,580	259	2,320	2,141	179	0	24
34	Nuclear Fuel Disposal	D8760	721	253	464	47	417	385	32	0	4
35	Meals & Entertainment	LABOR	32	14	18	3	15	14	1	0	0
36	Avoided Tax Interest	RTBASE	3,412	1,403	1,974	248	1,726	1,620	106	0	34
37	Total Tax Additions		29,075	11,289	17,468	2,053	15,415	14,382	1,033	0	318
38	**Total Inc Tax Adjustments**		(9,462)	(3,612)	(5,836)	(697)	(5,139)	(4,811)	(328)	0	(15)
39A	**Pres Taxable Net Income**		546	1,205	(1,059)	82	(1,141)	(589)	(551)	0	401
39B	**Prop Taxable Net Income**		21,081	9,487	11,193	1,643	9,550	9,415	135	0	401
40A	Pres Fed & State Inc Tax		214	473	(415)	32	(447)	(231)	(216)	0	157
40B	Prop Fed & State Inc Tax		8,270	3,722	4,391	644	3,747	3,694	53	0	157
41A	Pres Preliminary Return	(total); BASE	9,794	4,344	5,192	746	4,446	4,452	(7)	0	258
41B	Prop Preliminary Return	(total); BASE	22,273	9,377	12,638	1,695	10,943	10,532	410	0	258
42	Total AFUDC		0	0	0	0	0	0	0	0	0
43A	**Present Total Return**		9,794	4,344	5,192	746	4,446	4,452	(7)	0	258
43B	**Proposed Total Return**		22,273	9,377	12,638	1,695	10,943	10,532	410	0	258
44A	**Pres % Return on Rate Base**		4.05%	4.36%	3.71%	4.24%	3.63%	3.87%	-0.09%	0.00%	10.59%
44B	**Prop % Return on Rate Base**		9.20%	9.42%	9.02%	9.63%	8.93%	9.16%	5.45%	0.00%	10.60%
45A	**Present Common Return**		1,926	1,108	639	174	465	716	(252)	0	179
45B	**Proposed Common Return**		14,405	6,141	8,085	1,123	6,962	6,796	166	0	179
46A	**Pres % Ret on Common Rate Base**		1.54%	2.15%	0.88%	1.91%	0.73%	1.20%	-6.45%	0.00%	14.18%
46B	**Prop % Ret on Common Rate Base**		11.49%	11.91%	11.15%	12.32%	10.98%	11.42%	4.25%	0.00%	14.19%

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
Proposed Class Cost of Service Study

Case No. PU-07-______
Exhibit No. ______(PJZ-1
Schedule 2

			1=2+3+9	2	3=4+5	4	5=6 to 8	6	7	8	9
	Allow For Funds Used During Constr										
	Production	**Alloc**	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Transmiss**	**St Ltg**
1	Peaking Plant	D10C	0	0	0	0	0	0	0	0	0
2	Nuclear Fuel	D8760	0	0	0	0	0	0	0	0	0
3	Base Load	D8760	0	0	0	0	0	0	0	0	0
4	Total		0	0	0	0	0	0	0	0	0
	Transmission										
5	Gen Step Up Base	D8760	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10C	0	0	0	0	0	0	0	0	0
7	Total Gen Step Up		0	0	0	0	0	0	0	0	0
8	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0
9	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0
11	Total		0	0	0	0	0	0	0	0	0
	Distribution										
12	Generat Step Up	STRATH	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0
16	Total Substations		0	0	0	0	0	0	0	0	0
17	Overhead Lines	POL	0	0	0	0	0	0	0	0	0
18	Underground	PUL	0	0	0	0	0	0	0	0	0
19	Line Transformers	P68	0	0	0	0	0	0	0	0	0
20	Services	P69	0	0	0	0	0	0	0	0	0
21	Meters	C12WM	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73	0	0	0	0	0	0	0	0	0
23	Total		0	0	0	0	0	0	0	0	0
24	**General Plant**	PTD	0	0	0	0	0	0	0	0	0
25	**Electric Common**	PTD	0	0	0	0	0	0	0	0	0
26	**Total AFUDC**		0	0	0	0	0	0	0	0	0
	Labor Allocator										
	Production										
27	Other Prod - Cap	OXOPD	4,376	1,479	2,879	306	2,573	2,377	196	0	18
28	Other Prod - Ene	E8760	3,296	1,157	2,119	213	1,906	1,759	147	0	20
29	Total		7,672	2,636	4,998	519	4,480	4,136	343	0	37
	Transmission										
30	Stepup Subtrans	P5161A	21	7	14	1	12	11	1	0	0
31	Bulk Power Subs	D10T	714	271	440	57	384	368	16	0	3
32	Total		735	278	454	58	396	380	17	0	3
	Distribution										
33	Superv & Eng	ZDTS	314	170	128	26	102	98	4	0	16
34	Load Dispatch	D10T	156	59	96	12	84	81	3	0	1
35	Substation	P61	199	80	117	12	105	98	7	0	2
36	Overhead Lines	POL	633	314	274	44	230	220	10	0	45
37	Underground Lines	PUL	750	508	240	63	177	174	3	0	2
38	Line Transformer	P68	1	0	0	0	0	0	0	0	0
39	Meter	C12WM	143	85	57	29	29	26	3	0	0
40	Cust Installation	ZDTS	26	14	11	2	9	8	0	0	1
41	Street Lighting	P73	41	0	0	0	0	0	0	0	41
42	Miscellaneous	OXDTS	312	161	125	24	101	97	4	0	27
43	Total		2,575	1,392	1,049	212	837	803	34	0	135
44	**Cust Accounting**	C11WA	1,201	941	256	164	92	90	1	0	4
45	**Sales Expense**	C11P10	2	1	1	0	1	1	0	0	0
46	**Admin & General**	LABOR	6,026	2,609	3,329	472	2,857	2,662	195	0	89
47	**Service & Inform**	C11P10	169	100	67	14	53	49	4	0	2
48	**Labor**		18,381	7,957	10,153	1,439	8,714	8,120	594	0	270

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
Proposed Class Cost of Service Study

Backwards Revenue Calc

		1=2+3+9	2	3=4+5	4	5=6 to 8	6	7	8	9
	(1A) Modified Pres Rev	ND	Res	C&I Tot	Sm Non-D	Demand	Second	Primary	Transmiss	St Ltg
1	Present Preliminary Return (Before AFUDC)	9,794	4,344	5,192	746	4,446	4,452	(7)	0	258
2	1/(1-T) Rev Reqt (= 1.6455)	16,117	7,148	8,544	1,228	7,316	7,327	(11)	0	425
3	Total Inc Tax Adjustments	(9,462)	(3,612)	(5,836)	(697)	(5,139)	(4,811)	(328)	0	(15)
4	T/(1-T) Rev Reqt (= 0.6455)	(6,108)	(2,332)	(3,767)	(450)	(3,317)	(3,105)	(212)	0	(10)
5	Tot Op Exp W/o Regul Exp	176,625	67,037	107,888	12,341	95,547	88,656	6,890	0	1,701
6	- Other Retail Rev W/o Gr Earn, Etc	0	0	0	0	0	0	0	0	0
7	- Other Op Rev W/o Late Pay, Etc.	39,280	14,011	25,032	2,647	22,385	20,771	1,613	0	237
8	Modified Pres Net Oper Exp	137,345	53,026	82,856	9,694	73,162	67,885	5,277	0	1,464
9	Mod Pres Rev (R02) (component alloc)	147,354	57,842	87,632	10,472	77,160	72,106	5,054	0	1,880
	(1B) Present Revenue									
10	Tot Oper Exp (w/ Regul Exp)	176,696	67,064	107,930	12,346	95,584	88,691	6,893	0	1,702
11	- Other Retail Rev (w/ Gr Earn, Etc)	0	0	0	0	0	0	0	0	0
12	- Other Oper Rev (w/ Late Pay, Etc)	39,525	14,157	25,131	2,689	22,443	20,815	1,627	0	237
13	Net Oper Exp Rev Reqt	137,171	52,907	82,798	9,657	73,141	67,876	5,265	(0)	1,465
14	Tot Pres Rate Rev Reqt (R01)	147,179	57,724	87,575	10,436	77,139	72,097	5,042	0	1,881
	(2) Proposed Return									
15	Total Operating Exp	176,696	67,064	107,930	12,346	95,584	88,691	6,893	0	1,702
16	- Other Retail Rev (w/ Gr Earn, Etc)	0	0	0	0	0	0	0	0	0
17	- Prop Other Operating Rev	39,603	14,195	25,171	2,697	22,473	20,842	1,631	0	237
18	Prop Net Oper Exp Rev Reqt	137,093	52,870	82,759	9,649	73,110	67,848	5,262	(0)	1,464
19	Prop Preliminary Return	22,273	9,377	12,638	1,695	10,943	10,532	410	0	258
20	1/(1-T) Rev Reqt (= 1.6455)	36,651	15,430	20,796	2,790	18,006	17,331	675	0	425
21	T/(1-T) Rev Reqt (= 0.6455)	(6,108)	(2,332)	(3,767)	(450)	(3,317)	(3,105)	(212)	0	(10)
22	Total Proposed Rate Rev Reqt	167,636	65,968	99,787	11,988	87,799	82,074	5,725	(0)	1,880
	(3) Equal Return Rev									
23	T/(1-T) Rev Reqt (= 0.6455)	(6,108)	(2,332)	(3,767)	(450)	(3,317)	(3,105)	(212)	0	(10)
27	Equal Net Oper Exp Rev Reqt	137,093	52,870	82,759	9,649	73,110	67,848	5,262	(0)	1,464
28	Equal Rate of Ret (9.20%) x Rate Base	22,273	9,160	12,889	1,620	11,269	10,576	693	0	224
29	- AFUDC	0	0	0	0	0	0	0	0	0
30	Net Return	22,273	9,160	12,889	1,620	11,269	10,576	693	0	224
31	1/(1-T) Rev Reqt (= 1.6455)	36,652	15,073	21,209	2,666	18,543	17,403	1,140	0	369
32	Net Equal-Ret Rate Rev-Reqt (R99)	167,636	65,611	100,201	11,865	88,336	82,146	6,190	(0)	1,824
33	Tot Oper Rev - Equal	207,239	79,806	125,371	14,562	110,809	102,989	7,821	0	2,061
34	- Total Operating Exp	176,696	67,064	107,930	12,346	95,584	88,691	6,893	0	1,702
35	Equal Op Inc Before Inc Tax	30,543	12,742	17,442	2,216	15,226	14,298	928	0	360
36	Equal Taxable Net Income	21,081	9,130	11,606	1,519	10,087	9,487	600	0	345
37	Equal Fed & State Inc Tax	8,270	3,582	4,553	596	3,957	3,722	235	0	135
38	Proposed Common Return	14,405	5,924	8,336	1,048	7,288	6,840	448	0	145
39	Equal Return on Common	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%	0.00%	11.49%

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
Proposed Class Cost of Service Study

			1=2+3+6	2							
			1=2+6+9+30	2=3 to 5	6=7+8	7=12	8= 19 + 23	9=33	10=11+15	11=12 to 14	33=34 to 36
			1=2+3+9	2	3=4+5	4	5=6 to 8	6	7	8	9
INTERNAL ALLOCATORS		Intern:	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Transmiss**	**St Ltg**
1	**Rate Base: Col %'s**	**BASE-COL**	**1100.000%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**
			100.000%								
2	50% Cus, 50% Prod Plt	C11P10	100.000%	59.258%	39.345%	8.289%	31.057%	28.804%	2.252%	0.000%	1.396%
3	Peaking Plant Capacity	D10C	100.000%	32.814%	66.924%	7.385%	59.539%	55.037%	4.503%	0.000%	0.262%
4	100% Sum/Win Dmd, 0% Ene	D100E0	100.000%	30.236%	69.764%	7.632%	62.132%	57.340%	4.792%	0.000%	0.000%
5	61% Sum/Win Dmd, 39% Ene	D62E38	100.000%	36.842%	62.660%	7.370%	55.290%	52.241%	3.049%	0.000%	0.498%
6	Labor w/o (or w/) A&G	LABOR	100.000%	43.289%	55.239%	7.830%	47.410%	44.179%	3.231%	0.000%	1.471%
7	Net Plant In Service	NEPIS	100.000%	41.914%	57.125%	7.315%	49.809%	46.812%	2.998%	0.000%	0.961%
8	Dis O&M w/o Sup & Misc	OXDTS	100.000%	51.447%	39.979%	7.542%	32.437%	31.109%	1.328%	0.000%	8.574%
9	Other Prod Capac O&M	OXOPD	100.000%	33.799%	65.796%	6.989%	58.806%	54.322%	4.484%	0.000%	0.405%
10	O&M w/o Reg Ex & OXTS-Alloc'd A&G	OXTS	100.000%	37.521%	61.576%	6.943%	54.633%	50.618%	4.015%	0.000%	0.904%
11	Production Plant	P10	100.000%	34.520%	64.970%	6.700%	58.270%	53.800%	4.470%	0.000%	0.510%
12	Total P51 & P61A	P5161A	100.000%	33.879%	65.704%	6.957%	58.747%	54.265%	4.482%	0.000%	0.417%
13	Distribution Plant	P60	100.000%	57.446%	39.424%	7.610%	31.813%	30.741%	1.073%	0.000%	3.130%
14	Distr Substn Plant	P61	100.000%	40.159%	58.808%	6.088%	52.720%	49.333%	3.386%	0.000%	1.033%
15	Line Transformer Plant	P68	100.000%	50.267%	49.354%	6.448%	42.906%	42.690%	0.216%	0.000%	0.379%
16	Services Plant	P69	100.000%	78.414%	21.586%	3.256%	18.329%	18.329%	0.000%	0.000%	0.000%
17	Dist Plt Overhead Lines	POL	100.000%	49.655%	43.304%	6.964%	36.341%	34.770%	1.571%	0.000%	7.041%
18	Real Est & Property Tax	PT0	100.000%	43.090%	55.458%	7.302%	48.157%	45.304%	2.853%	0.000%	1.452%
19	Produc, Trans & Distrib	PTD	100.000%	40.030%	58.899%	7.082%	51.817%	48.428%	3.388%	0.000%	1.071%
20	Dist Plt Undground Lines	PUL	100.000%	67.721%	32.006%	8.389%	23.616%	23.228%	0.389%	0.000%	0.273%
21	**Rev w/o Reg, etc: Col %**	**R02-COL**	**1100.000%**	**N/A**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**
			100.000%	**44.35%**	**53.01%**	**7.62%**	**45.39%**	**45.46%**	**-0.07%**	**0.00%**	**2.64%**
			100.000%	**42.10%**	**56.74%**	**7.61%**	**49.13%**	**47.29%**	**1.84%**	**0.00%**	**1.16%**
22	Rate Base (Non-Column)	RTBASE	100.000%	41.126%	57.867%	7.274%	50.593%	47.483%	3.110%	0.000%	1.007%
23	Stratified Hydro Baseload	STRATH	100.000%	34.555%	64.929%	6.686%	58.244%	53.774%	4.469%	0.000%	0.515%
24	Transmission & Distrib	TD	100.000%	49.310%	48.672%	7.726%	40.946%	39.380%	1.566%	0.000%	2.017%
25	Labor Dis w/o Sup & Eng	ZDTS	100.000%	54.050%	40.722%	8.223%	32.499%	31.167%	1.332%	0.000%	5.228%

			1=2+3+9	2	3=4+5	4	5=6 to 8	6	7	8	9
INTERNAL DATA			**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Transmiss**	**St Ltg**
26	Labor w/o A&G	LABOR(S)	12,354	5,348	6,824	967	5,857	5,458	399	0	182
27	Dis O&M w/o Sup, Cust Install & Misc	OXDTS	4,459	2,294	1,783	336	1,446	1,387	59	0	382
28	O&M w/o Reg Ex & OXTS-Alloc'd A&G	OXTS	145,610	54,634	89,661	10,110	79,551	73,704	5,846	0	1,316
29	Total P51 & P61A	P5161A	2,774	940	1,823	193	1,630	1,505	124	0	12
30	Produc, Trans & Distrib	PTD	568,463	227,554	334,818	40,261	294,558	275,296	19,262	0	6,090
31	Transmission & Distrib	TD	211,759	104,419	103,068	16,361	86,707	83,390	3,317	0	4,271
32	Labor Dis w/o Sup & Eng, Cust Install	ZDTS	2,235	1,208	910	184	726	696	30	0	117

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
Proposed Class Cost of Service Study

			1=2+3+9	2	3=4+5	4	5=6 to 8	6	7	8	9
EXTERNAL ALLOCATORS		Extern:	**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Transmiss**	**St Ltg**
1	Customers - Ave Monthly	C11	100.00%	84.00%	13.72%	9.88%	3.84%	3.81%	0.03%	0.00%	2.28%
2	Cust Acctg Wtg Factor	C11WA	100.00%	78.34%	21.31%	13.69%	7.62%	7.52%	0.10%	0.00%	0.35%
3	Mo Cus Wtd By Mtr Invest	C12WM	100.00%	59.81%	40.13%	20.06%	20.07%	18.25%	1.82%	0.00%	0.06%
4	Sec & Pri Customers	C61PS	100.00%	85.81%	14.09%	10.14%	3.95%	3.91%	0.04%	0.00%	0.10%
5	C62Sec, w/o Ltg & C/I Underground	C62NL	100.00%	94.58%	5.42%	3.91%	1.51%	1.51%	0.00%	0.00%	0.00%
6	Secondary Customers	C62Sec	100.00%	85.84%	14.06%	10.15%	3.91%	3.91%	0.00%	0.00%	0.10%
7	Summer Peak Resp KW	D10S	100.00%	30.24%	69.76%	7.63%	62.13%	57.34%	4.79%	0.00%	0.00%
8	Transmission Demand %	D10T	100.00%	37.89%	61.67%	7.92%	53.75%	51.56%	2.20%	0.00%	0.44%
9	Winter Peak Resp KW	D10W	100.00%	40.46%	58.51%	6.65%	51.85%	48.21%	3.65%	0.00%	1.04%
10	Dmd Equiv of E8760	D8760	100.00%	35.11%	64.30%	6.46%	57.83%	53.37%	4.46%	0.00%	0.60%
11	Sec, Pri & TT, Class Coin kW @ Subst	D60Sub	100.00%	40.27%	58.68%	6.06%	52.62%	49.24%	3.38%	0.00%	1.05%
12	Sec & Pri, Cl Coin kW (no Min Sys; adj	D61PS	100.00%	30.21%	68.85%	6.13%	62.72%	58.69%	4.03%	0.00%	0.94%
13	D62Sec, w/o Ltg & C/I Underground	D62NLL	100.00%	35.43%	64.57%	1.51%	63.06%	63.06%	0.00%	0.00%	0.00%
14	Sec, Class Coin kW (w/o Min Sys kW)	D62SecL	100.00%	27.08%	72.41%	3.87%	68.54%	68.54%	0.00%	0.00%	0.52%
15	Direct Assign Street Lighting	DASL	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
16	On + Off Sales MWH	E8760	100.00%	35.11%	64.30%	6.46%	57.83%	53.37%	4.46%	0.00%	0.60%
17	Street Lighting (Dir Assign)	P73	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
18	Present Rev	R01	100.00%	39.22%	59.50%	7.09%	52.41%	48.99%	3.43%	0.00%	1.28%

			1=2+3+9	2	3=4+5	4	5=6 to 8	6	7	8	9
APPLIED EXTERNAL DATA (BIG or LITTLE)			**ND**	**Res**	**C&I Tot**	**Sm Non-D**	**Demand**	**Second**	**Primary**	**Transmiss**	**St Ltg**
19	Customers - B Basis	C10	85,336	73,223	12,024	8,656	3,368	3,338	30	0	89
20	Cust - Ave Monthly (C10-Area Lt)	C11	87,633	73,609	12,024	8,656	3,368	3,338	30	0	2,000
21	Mo Cus Wtd By Cus Acct	C11WA	93,709	73,416	19,968	12,830	7,139	7,044	95	0	325
22	Cust Acctg Wtg Factor	C11WAF	10.81	1.00	6.72	1.48	5.23	2.11	3.12	0.00	3.10
23	Cust-Ave Mo (C11 w/ Dir Assign St Ltg	C12	85,645	73,609	12,024	8,656	3,368	3,338	30	0	12
24	Mo Cus Wtd By Mtr Invest	C12WM	6,164,138	3,686,694	2,473,850	1,236,811	1,237,039	1,125,151	111,888	0	3,594
25	Meter Invest / Cust Factor	C12WMF	4,507	50	4,157	143	4,015	337	3,677	0	299
26	Sec & Pri Customers	C61PS	85,336	73,223	12,024	8,656	3,368	3,338	30	0	89
27	C62Sec, w/o Ltg & C/I Underground	C62NL	77,421	73,223	4,198	3,030	1,168	1,168	0	0	0
28	Secondary Customers	C62Sec	85,306	73,223	11,994	8,656	3,338	3,338	0	0	89
29	Summer Peak Resp KW	D10S	454,961	137,561	317,400	34,724	282,676	260,876	21,800	0	0
30	Dmd (D10S x Fact + D10W)/1000	D10T	10,000,000	3,789,197	6,166,906	791,865	5,375,041	5,155,531	219,510	0	43,897
31	Winter Peak Resp KW	D10W	388,237	157,068	227,139	25,821	201,318	187,165	14,153	0	4,030
32	Dmd Equiv of E20	D20	3,136,445	1,084,866	2,029,456	200,810	1,828,646	1,685,492	143,154	0	22,123
33	Sec, Pri & TT, Class Coin kW @ Subst	D60Sub	586,281	236,103	344,044	35,553	308,492	288,693	19,799	0	6,134
34	Sec & Pri, Class Coin kW (w/o Min Sys	D61PS	491,152	148,378	338,170	30,110	308,060	288,265	19,795	0	4,604
35	D62Sec, w/o Ltg & C/I Underground	D62NLL	1,834,242	649,891	1,184,350	27,694	1,156,657	1,156,657	0	0	0
36	Sec, Class Coin kW (w/o Min Sys kW)	D62SecL	521,484	198,504	318,375	30,110	288,265	288,265	0	0	4,604
37	Annual Billing kW	D99	3,530	0	3,530	0	3,530	3,305	226	0	0
38	Summer Billing kW	D99S	1,222	0	1,222	0	1,222	1,143	80	0	0
39	Winter Billing kW	D99W	2,308	0	2,308	0	2,308	2,162	146	0	0
40	Non-Coinc Pk Second	DN-Sec	4,039,999	649,891	3,383,858	79,124	3,304,734	3,304,734	0	0	6,249
41	Energy At Gener MWH	E10	2,394,439	849,131	1,525,070	147,459	1,377,611	1,267,801	109,810	0	20,238
42	On Peak Wtg Factor %	E11	N/A	35.81%	N/A	46.68%	81.68%	42.50%	39.17%	0.00%	12.02%
43	Wtd On + Off Sales MWH	E20	3,136,445	1,084,866	2,029,456	200,810	1,828,646	1,685,492	143,154	0	22,123
44	MWH Sales @ Gen	E99	2,217,924	782,202	1,417,004	135,756	1,281,248	1,177,078	104,171	0	18,717

ALLOCATOR CONSTANTS

				2006 Values
1	% D10 O&M Econ Develop	Econ Dev Dmd	100.00%	
2	% D10 O&M CIP/DSM	CIP Dmd	62.29%	
3	On Peak Energy Wtg Factor For E20	ONPKWF	1.775	
4	APL Inv In OH Lines: Dir Assignable	POLAPL	776	
5	Summer Factor	SFAC	0.7478	0.7478
6	Overhead Lines St Ltg Comp Owned	QQOSL1	2.440%	2.440%
7	Overhead Lines Area Lighting	QQOSL2	1.133%	1.133%
8	Overhead Lines Primary - Customer	QQ64C	24.951%	24.951%
9	Overhead Lines Primary - Demand	QQ64D	39.998%	39.998%
10	Overhead Lines Secondary - Customer	QQ65C	15.699%	15.699%
11	Overhead Lines Secondary - Demand	QQ65D	15.780%	15.780%
12	Overhead Total		100.000%	100.000%
13	Underground Primary - Customer	QQ66C	44.504%	44.504%
14	Underground Primary - Demand	QQ66D	9.256%	9.256%
15	Underground Secondary - Customer	QQ67C	24.198%	24.198%
16	Underground Secondary - Demand	QQ67D	22.041%	22.041%
17	Underground Total		100.000%	100.000%
18	Line Trans Secondary - Customer	QQ68C	39.180%	39.180%
19	Line Trans Secondary - Demand	QQ68D	55.460%	55.460%
20	Line Trans Primary - Demand	QQ68P	5.360%	5.360%
21	Line Trans Total		100.000%	100.000%
22	Services - Customer	QQ69C	72.670%	72.670%
23	Services - Demand	QQ69D	27.330%	27.330%
24	Services Total		100.000%	100.000%
25	Stratified Nuclear Baseload (JCOSS on	STRNBL	0.8442	
26	Stratified Fossil Baseload (JCOSS only	STRFBL	0.7365	
27	Stratified Hydro Baseload	STRHBL	0.7593	

Switches for comparing 1993 to 2006
(Also see Int and Ener switches)

0	Distribution: Overhead / Underground Shift plant pages)
0	Meter Price Shift
0	Production Plant: Base / Peaking Shift (plant pages)
0	Peaking Plant: Summer / Winter Shift (only page 4)
0	Minimum System Shift

CALCULATED CONSTANTS

			Cost	Ratio	
28	Net Overhead Lines Investment	QPOLS			24,280
29	Ovhd Lines St Ltg Co - Assignable	QQSL1			592
30	Ovhd Lines Area Ltg - Assignable	QQSL2			275
31	Ovhd St Lt + Area Lt + Dir Assign	QQSLTOT			1,644
32	**Peaking Factor For Purchased Power**				0.570
33	Total Proposed Retail Revenue				167,636
34	Ratio: Prop vs Pres Retail Revenue				1.1390
35	Minn Total State & Fed Tax Rate	TAXRATE			39.23%
			Cost	**Ratio**	**Wtd Cost**
36	**Long Term Debt**		6.79%	45.61%	3.10%
37	**Short Term Debt**		5.74%	2.62%	0.15%
38	**Preferred Stock**		0.00%	0.00%	0.00%
39	**Equity**		11.50%	51.77%	5.95%

CALCULATED CONSTANTS

40	Proposed Overal Return		9.2000%
41	Interest Exp Factor	DETFACT	3.2500%
42	Debt Ratio	DETRATIO	48.2300%
43	Embedded Cost of Debt	DETCOST	6.7330%
44	Rev Increase Percent	INCRPCT	13.8991%
45	1 / (1 - Tax Rate) Factor	ONEOVER	164.5549%
46	Tax Rate / (1 - Tax Rate) Factor	TAXOVER	64.5549%

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
Proposed Class Cost of Service Study
Allocator Index

Alloc	Expense / Revnue	Pg	Ln
(R16C); R02	Incr Late Pay - Prop	7	24
(total); BASE	Pres Preliminary Return	11	41A
(total); BASE	Prop Preliminary Return	11	41B
C11	Connection Charges	7	13
C11	Connect Fees, Cus Adv	11	14
C11P10	Cust Assist Exp - Non-CIP	8	29
C11P10	Instructional Advertising	8	31
C11P10	Sales Expense	12	45
C11P10	Service & Inform	12	47
C11WA	Customer Accounting	8	13
C11WA	Cust Accounting	12	44
C12WM	Meters	4	41
C12WM	Meters	5	21
C12WM	Meters	5	48
C12WM	Meters	6	21
C12WM	Meters	8	7
C12WM	Meters	9	20
C12WM	Meters	9	45
C12WM	Meters	10	20
C12WM	Meters	10	21
C12WM	Meters	11	21
C12WM	Meters	12	21
C12WM	Meter	12	39
C61PS	Primary Customer	4	20
C61PS	Primary Customer	4	28
C62NL	Second Customer	4	39
C62Sec	Second Customer	4	23
C62Sec	Second Customer	4	31
C62Sec	Second Customer	4	36
D100E0	Econ Development	8	14
D10C	Interruptible Capacity Costs	2	7
D10C	Interruptible Capacity Costs	3	7
D10C	Gen Step Up Peak	4	8
D10C	Peaking Plant	5	1
D10C	Decom Int Peaking	5	2
D10C	Gen Step Up Peak	5	6
D10C	Peaking Plant	5	28
D10C	Gen Step Up Peak	5	33
D10C	Peaking Plant	6	1
D10C	Gen Step Up Peak	6	6
D10C	Purchases: Cap Peak	7	29
D10C	Capacity Peaking	7	38
D10C	Peaking Plant	9	1
D10C	Gen Step Up Peak	9	5
D10C	Peaking Plant	9	26
D10C	Gen Step Up Peak	9	30
D10C	Peaking Plant	10	1
D10C	Gen Step Up Peak	10	5
D10C	Gen Step Up Peak	10	6
D10C	Peaking Plant	10	29
D10C	Peaking Plant	11	1
D10C	Gen Step Up Peak	11	6
D10C	Peaking Plant	12	1
D10C	Gen Step Up Peak	12	6

Alloc	Expense / Revnue	Pg	Ln
D10S	Summer Peak	4	1
D10T	Bulk Transmission	4	10
D10T	Bulk Transmission	4	15
D10T	Bulk Transmission	5	8
D10T	Bulk Transmission	5	13
D10T	Bulk Transmission	5	35
D10T	Bulk Transmission	5	40
D10T	Bulk Transmission	6	8
D10T	Bulk Transmission	6	13
D10T	Interchg Tr Bulk Supply	7	10
D10T	Joint Op Agree-Other PSCo Rev	7	15
D10T	Misc Ancillary Trans Rev	7	17
D10T	MISO	7	18
D10T	Other	7	19
D10T	Transmission Exp	7	44
D10T	Load Dispatching	8	2
D10T	Bulk Transmission	9	7
D10T	Bulk Transmission	9	12
D10T	Bulk Transmission	9	32
D10T	Bulk Transmission	9	37
D10T	Bulk Transmission	10	8
D10T	Bulk Transmission	10	12
D10T	Bulk Transmission	10	13
D10T	Bulk Transmission	10	32
D10T	Bulk Transmission	11	8
D10T	Bulk Transmission	11	13
D10T	Bulk Transmission	12	8
D10T	Bulk Transmission	12	13
D10T	Bulk Power Subs	12	31
D10T	Load Dispatch	12	34
D10W	Winter Peak	4	2
D60Sub	Distrib Function	4	11
D60Sub	Distrib Function	4	16
D60Sub	Distrib Function	5	9
D60Sub	Distrib Function	5	14
D60Sub	Distrib Function	5	36
D60Sub	Distrib Function	5	41
D60Sub	Distrib Function	6	9
D60Sub	Distrib Function	6	14
D60Sub	Distrib Function	9	8
D60Sub	Distrib Function	9	13
D60Sub	Distrib Function	9	33
D60Sub	Distrib Function	9	38
D60Sub	Distrib Function	10	8
D60Sub	Distrib Function	10	9
D60Sub	Distrib Function	10	13
D60Sub	Distrib Function	10	14
D60Sub	Distrib Function	11	9
D60Sub	Distrib Function	11	14
D60Sub	Distrib Function	12	9
D60Sub	Distrib Function	12	14
D62E38	CIP Performance	7	6
D62E38	CIP Total	8	30
D61PS	Primary Capacity	4	19

Alloc	Expense / Revnue	Pg	Ln
D61PS	Primary Capacity	4	27
D61PS	Primary	4	34
D62NLL	Second Capacity	4	38
D62SecL	Second Capacity	4	22
D62SecL	Second Capacity	4	30
D62SecL	Second Capacity	4	35
D8760	Base Load	4	4
D8760	Nuclear Fuel	4	5
D8760	Gen Step Up Base	4	7
D8760	Nuclear Fuel	5	2
D8760	Decom Int Baseload	5	3
D8760	Base Load	5	3
D8760	Gen Step Up Base	5	5
D8760	Base Load	5	29
D8760	Nuclear Fuel	5	30
D8760	Gen Step Up Base	5	32
D8760	Base Load	6	2
D8760	Nuclear Fuel	6	3
D8760	Gen Step Up Base	6	5
D8760	Purchases: Cap Base	7	30
D8760	Capacity Baseload	7	39
D8760	Base Load	9	2
D8760	Gen Step Up Base	9	4
D8760	Base Load	9	27
D8760	Gen Step Up Base	9	29
D8760	Nuclear Fuel	10	2
D8760	Base Load	10	3
D8760	Gen Step Up Base	10	4
D8760	Gen Step Up Base	10	5
D8760	Base Load	10	30
D8760	Nuclear Fuel	11	2
D8760	Base Load	11	3
D8760	Gen Step Up Base	11	5
D8760	Nuclear Fuel Disposal	11	34
D8760	Nuclear Fuel	12	2
D8760	Base Load	12	3
D8760	Gen Step Up Base	12	5
DASL	Street Lighting	4	25
Dir Assign	Direct Assign	4	12
Dir Assign	Direct Assign	4	17
Dir Assign	Street Lighting	4	42
Dir Assign	Direct Assign	5	10
Dir Assign	Direct Assign	5	15
Dir Assign	Direct Assign	5	37
Dir Assign	Direct Assign	5	42
Dir Assign	Direct Assign	6	10
Dir Assign	Direct Assign	6	15
Dir Assign	Direct Assign	7	22
Dir Assign	Street Lighting	8	9
Dir Assign	Direct Assign	9	9
Dir Assign	Direct Assign	9	14
Dir Assign	Direct Assign	9	34
Dir Assign	Direct Assign	9	39
Dir Assign	Direct Assign	10	10

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
Proposed Class Cost of Service Study
Allocator Index

Alloc	Expense / Revnue	Pg	Ln
Dir Assign	Direct Assign	10	14
Dir Assign	Direct Assign	10	15
Dir Assign	Direct Assign	10	33
Dir Assign	Direct Assign	11	10
Dir Assign	Direct Assign	11	15
Dir Assign	Direct Assign	12	10
Dir Assign	Direct Assign	12	15
E8760	Fuel Inventory	6	27
E8760	Interchg Prod Energy	7	9
E8760	Dist Int Sales; Oth Serv	7	11
E8760	Sales For Resale	7	14
E8760	Production Assoc'd Rev	7	16
E8760	Fuel	7	28
E8760	Purchases: Other Energy	7	32
E8760	Interchg Agr Energy	7	35
E8760	Energy	7	41
E8760	Nuclear Fuel Book Burn	11	33
E8760	Other Prod - Ene	12	28
LABOR	Non-Plant Related	5	55
LABOR	Non-Plant Assets & Liab	6	33
LABOR	Salaries	8	15
LABOR	Outside Services	8	18
LABOR	Pensions & Benefits	8	20
LABOR	Injuries & Claims	8	21
LABOR	Amortizations	8	33
LABOR	Payroll Taxes	9	52
LABOR	Non - Plant Related	10	27
LABOR	Non - Plant Related	11	27
LABOR	Meals & Entertainment	11	35
LABOR	Admin & General	12	46
NEPIS	TBT Investment	4	21
NEPIS	TBT Acc Def Tax	5	54
NEPIS	Miscellaneous	6	31
NEPIS	Insurance	6	33
NEPIS	Property Insurance	8	19
NEPIS	TBT Defer Inc Tax	10	26
NEPIS	TBT Misc Net Exp	10	28
NEPIS	TBT Misc Net Exp	11	7
NEPIS	TBT Defer Inc Tax	11	26
OXDTS	Customer Install'n	8	8
OXDTS	Miscellaneous	8	10
OXDTS	Miscellaneous	12	42
OXOPD	Other Prod - Cap	12	27
OXTS	Office Supplies	8	16
OXTS	Admin Transfer Credit	8	17
OXTS	General Advertising	8	23
OXTS	Contributions	8	24
OXTS	Misc General Exp	8	25
OXTS	Rents	8	26
OXTS	Maint of General Plant	8	27
P10	Production	6	28
P10	Interchg Prod Capacity	7	8
P10	Interchg Agr Capacity	7	34
P5161A	Stepup Subtrans	12	30
P61	Substations	8	3
P61	Substation	12	35
P68	Line Transformers	5	19
P68	Line Transformers	5	46
P68	Line Transformers	6	19
P68	Line Transformers	8	6
P68	Line Transformers	9	18
P68	Line Transformers	9	43
P68	Line Transformers	10	18
P68	Line Transformers	10	19
P68	Line Transformers	11	19
P68	Line Transformers	12	19
P68	Line Transformer	12	38
P69	Services	5	20
P69	Services	5	47
P69	Services	6	20
P69	Services	9	19
P69	Services	9	44
P69	Services	10	19
P69	Services	10	20
P69	Services	11	20
P69	Services	12	20
P73	Street Lighting	5	22
P73	Street Lighting	5	49
P73	Street Lighting	6	22
P73	Street Lighting	9	21
P73	Street Lighting	9	46
P73	Street Lighting	10	21
P73	Street Lighting	10	22
P73	Street Lighting	11	22
P73	Street Lighting	12	22
P73	Street Lighting	12	41
POL	Overhead Lines	5	17
POL	Overhead Lines	5	44
POL	Overhead Lines	6	17
POL	Dist Overhd Line Rent	7	12
POL	Overhead Lines	8	4
POL	Rents (Pole Attachmts)	8	11
POL	Overhead Lines	9	16
POL	Overhead Lines	9	41
POL	Overhead Lines	10	17
POL	Overhead Lines	10	35
POL	Overhead Lines	11	17
POL	Overhead Lines	12	17
POL	Overhead Lines	12	36
PROREV	Proposed Rate Revenue	7	2
PT0	Working Cash	6	34
PTD	General Plant	4	44
PTD	Electric Common	4	45
PTD	General Plant	5	24
PTD	Electric Common	5	25
PTD	General Plant	5	51
PTD	Electric Common	5	52
PTD	General Plant	6	24
PTD	Electric Common	6	25
PTD	General Plant	9	23
PTD	Electric Common	9	24
PTD	General Plant	9	48
PTD	Electric Common	9	49
PTD	General Plant	10	24
PTD	Electric Common	10	25
PTD	General Plant	10	38
PTD	Electric Common	10	39
PTD	Book Depr Cleared To Oper	11	11
PTD	Tax Capitalized Leases	11	12
PTD	General Plant	11	24
PTD	Electric Common	11	25
PTD	General Plant	12	24
PTD	Electric Common	12	25
PUL	Underground	5	18
PUL	Underground	5	45
PUL	Underground	6	18
PUL	Underground Lines	8	5
PUL	Underground	9	17
PUL	Underground	9	42
PUL	Underground	10	18
PUL	Underground	10	36
PUL	Underground	11	18
PUL	Underground	12	18
PUL	Underground Lines	12	37
R01,	Incr Misc Serv - Prop	7	23
R01; (calc)	Present Rate Revenue	7	1
R01; R02	Interdepartmental	7	3
R01; R02	Gross Earnings Tax	7	4
R01; R02	Regulatory Exp	8	22
R01; R02	Gross Earnings Tax	9	51
R16C; R02	Late Pay Chg - Pres	7	20
RTBASE	Avoided Tax Interest	11	36
RTBASE	Rev Items, Equal Alloc	13	26
STRATH	Generat Step Up	4	14
STRATH	Generat Step Up	5	12
STRATH	Generat Step Up	5	39
STRATH	Generat Step Up	6	12
STRATH	Generat Step Up	9	11
STRATH	Generat Step Up	9	36
STRATH	Generat Step Up	10	11
STRATH	Generat Step Up	10	12
STRATH	Generat Step Up	11	12
STRATH	Generat Step Up	12	12
TD	Trans & Distr	6	29
ZDTS	Supervision & Eng'rg	8	1
ZDTS	Superv & Eng	12	33
ZDTS	Cust Installation	12	40

GUIDE TO EMBEDDED ELECTRIC CLASS COST OF SERVICE STUDY (CCOSS)

I. Preliminary Discussion of Information Flow

This document primarily discusses the Class Cost of Service Study ("CCOSS"). But to give the CCOSS a proper perspective, it's necessary to first briefly discuss the three steps of information flow that occur within a rate case. First, the utility's plant assets must be "functionalized." Functionalizing relies on FERC rules and definitions to first divide the utility's assets between the gas and electric utilities. Then the assets of each utility are further divided into six FERC categories. (Please see Attachment 1.) The first four categories (Production, Storage, Transmission and Distribution) roughly follow the flow of energy, from its creation or extraction all the way to its consumption by end users. The fifth category, General, refers to plant items that are strictly related to a single utility but which relate to two or more of the first four categories (e.g., a utility office building that is used only by electric employees or only by gas employees). The sixth category, Common, is similar to General in that it refer to two or more of the first four categories. But Common plant also relates to both the gas and electric utilities (e.g., the Company's General Office building in downtown Minneapolis).

The second rate case information flow involves a Jurisdictional Cost of Service Study ("JCOSS"). A JCOSS takes all the functionalized plant items, as well as all expense items, and splits those costs among the jurisdictions (i.e., states). And the third flow involves using the CCOSS to further split each state-level cost element into the amount for each customer class. (Please see Attachments 2 and 3 for different portrayals of this cost process.)

II. Introduction to Class Cost of Service Study

A fully distributed, embedded CCOSS apportions ("allocates") the total cost of providing utility service ("revenue requirements") to the various service classes in a way that reflects the engineering and operating characteristics of the electric utility system. Given these electric utility cost characteristics, the objective of the CCOSS is to determine for each service class the total costs of service, which includes the costs associated with investment in plant as well as operating expenses. (Please see Attachment 4.)

Xcel Energy's CCOSS is divided into five sections. (Please see Attachment 5.)

The Summary section contains three pages. Page 1 contains a high-level summary of the Rate Base and Income Statement. Pages 2 and 3 both show billing components, such as the customer charge, demand charge and energy charge. However, Page 2 derives these billing components by assuming each customer class provides the same return on investment ("ROI"). In other words, these are "ideal" rates. Page 3 contains more "real world" rates that reflect the variations in ROI that customer classes are actually allowed to pay. (Note that throughout most of the rate case process, these will be labeled "Proposed" rates. But once the North Dakota Public Utility Commission has issued an order, a revised version of the CCOSS will be prepared that labels these as "Ordered" rates.)

The Rate Base section contains three pages. Page 4 shows Original Plant in Service. The top half of Page 5 shows Accumulated Depreciation. This page and a half contain most of the Rate Base dollars, and the resulting Net Plant amount comes close to being the final Rate Base amount. However, certain adjustments must still be made. The bottom half of Page 5 contains subtractions, which currently consists solely of Accumulated Deferred Income Taxes. Page 6 contains additions. These are primarily Construction Work in Progress ("CWIP" which is pronounced "see-wip"). However, there are also some other miscellaneous additions. From a general accounting perspective, Rate Base is fairly similar to the Balance Sheet that non-utilities include in their annual reports.

The Income Statement section contains five pages. It would be possible to have two complete, 5-page Income Statements – one for Present rates and one for Proposed / Ordered rates. But since nearly all the lines would be identical, it has proved more efficient to combine them into a single, joint Income Statement. Generally speaking, an income statement consists of "revenues minus expenses." In this case, all the revenues are shown on the top of Page 7. Revenues can be divided into Retail Revenues, Other Retail Revenues and Other Operating Revenues. While the first category contains only a few lines, it contains the most dollars. These are the actual prices that will be determined as part of the rate case. The second and third categories contain many small, miscellaneous revenue sources. To the extent the utility receives Other Retail Revenue or Other Operating Revenue, the amount of Retail Revenue that the utility needs to collect is reduced.

Expenses begin on the bottom of Page 7, specifically Fuel and Purchased Power costs, as well as Transmission. Page 8 contains Distribution and other miscellaneous expenses. Note that the expenses on these two pages are collectively termed Operating and Maintenance (or "O & M") expenses. The top half of Page 9 contains Book Depreciation. (This is the current year's portion of the Accumulated Depreciation on Page 5.) The bottom half of Page 9 contains Property Taxes. The top half of Page 10 contains the Provision for Deferred Income Taxes. (This is the current year's portion of the Accumulated Deferred Income Taxes on Page 5.) The bottom half of Page 10 contains the Current Inventory Tax Credit (which has almost been phased out by the Federal Government). This page then also shows a Total Operating Expense subtotal is determined, based on all the expenses on Page 7 through 10. This expense subtotal is subtracted from total revenues to derive Operating Income Before Income Tax. It's helpful to imagine this final subtotal being "on hold" for a moment, while income taxes are determined.

The top half of Page 11 contains Tax Depreciation (similar to the Book Depreciation on Page 9). The bottom of Page 11 determines total income tax deductions and additions and applies them to Operating Income Before Income Tax (from Page 10) to derive Taxable Income. The utility's corporate tax rate is applied to Taxable Income, to derive Income Tax. Only then does the "revenues minus expenses" process resume, as Income Tax is subtracted from Operating Income Before Income Tax, to derive Preliminary Present and Proposed / Ordered Return. An adjustment is made for Authorized Funds Used During Construction ("AFUDC" or "AFC"). Note that this is essentially imputed income. The final result is simply Present and Proposed / Ordered Return. These total return amounts are compared against the total Rate Base to get the Return On Rate Base percentage. And the common shareholder portion of the return is compared to the common shareholder portion of rate base to get the Common Return percentage.

The Miscellaneous Calculations section contains two pages. The top half of Page 12 contains a full development of AFUDC. The bottom half of Page 12 contains the Labor Allocator. And Page 13 develops various revenue components of Present, Proposed / Ordered and Equal Revenue. The importance of this last page will be discussed later.

The Allocators section contains three pages. Page 14 contains Internal Allocators. These are allocators that can't be fully known prior to the running of the CCOSS because they are based on elements that only come together within the CCOSS. Page 15 contains External Allocators. These allocators are typically based on independent studies (such as the sales forecast) and can thus be fully known prior to the running of the CCOSS. For both of these pages, there is a block of lines containing the "raw" numbers (e.g. one line might contain the number of customers in each class). And there is a corresponding block of the allocator percents. Note that the code names that appear on these pages correspond to the codes shown in the "Alloc" column of pages 4 through 12. Lastly, Page 16 contains a number of constants, such as the components of the utility's capital structure.

III. Splits To Billing Component and Unbundled Component

It has already been noted that the CCOSS splits total costs in at least two "dimensions," namely FERC functionalization and customer class. But to properly identify all costs, they must be split into two additional dimensions. They must be split into billing component (customer charge, demand charge and energy charge). And because of potential deregulation studies, they must be split into unbundled business unit components (Generation Company or Genco, Transmission Company or Transco, Distribution Company or Disco, and Customer Company or Cusco). However, the CCOSS is processed in a spreadsheet – which has only three dimensions. To accommodate the four required dimensions, the last two components share a dimension. (Please see attachment 6.) In the 3-D view of the spreadsheet, the 500 some JCOSS numbers are placed in a single column on the "surface" of the cube. They are then allocated to the right, to the classes. Then each class amount is allocated down, to billing and unbundling components.

Many of the billing and unbundling components just mentioned are actually broken into subcomponents. E.g., the energy charge is broken into on-peak and off-peak. Likewise, customer charge is broken into the service drop (the wiring and metering that connect the customer to the electric grid) and energy services (meter reading and billing services). And generation demand is divided into base load, summer peaking and winter peaking. The full set of relationships is shown in Attachment 7. All the lower level components (which are in non-bold font) can either be added upwards, to get unbundled business units, which in turn can be added to the left, to get the grand total. Or the lower level components can be added to the left, to get billing components, which in turn can be added upwards, to get the same grand total. Note that while 20 distinct cost items appear on Attachment 7, only 18 layers exist in the spreadsheet on Attachment 6. That's because Transco and Transmission are actually identical and only need a single spreadsheet layer. The same is true for Cusco and Customer.

Because of the complexity of these cost allocation relationships, there is great potential for formula errors in the spreadsheet. To deal with that problem, check sums were installed throughout the spreadsheet. The sums not only verify that the layers add up for each line. They also verify that the class columns add back up to the initial JCOSS amount. While this process catches virtually any error that is introduced into the file, it also makes changing the program very difficult. Nearly every allocated line becomes part of a subtotal that is used to form an additional allocator. Therefore, an allocation error on one line will often cause additional errors on a few dozen other lines. However, when presented with so many errors, it can be quite difficult to go backward and determine which is the "real" error and which ones are just "echo" errors. Sometimes a change that appears fairly modest might cause several real errors, thus leading to hundreds of echo errors and many hours or days of debugging.

IV. Component Revenue Requirements

Referring to Attachment 8, note that on the TOTAL layer, both revenues and expenses can be allocated to class. Therefore, the income statement can be processed for each class. I.e., all the expenses can be subtracted from revenue, in order to determine the net return. However, the same is not true on the 17 sublevels. Although costs and even Other Retail Revenue and Other Operating Revenue can be allocated to the sublevels, there is no way to directly allocate the Retail Revenue Requirement. Therefore, an indirect method must be used. First, the return amounts that have already been determined on the TOTAL layer are allocated to the sublevels using Rate Base. (This allocator is appropriate because return on investment is directly related to the investment itself, which is the Rate Base.) Thus for any given class column on any given sublevel, all values will be known except Retail Revenue Requirement. So algebra can be employed to convert the basic income statement formula (revenue minus expense equals return) into a more useful form (return plus expenses equals revenue). This can be informally referred to as the "backwards revenue calculation."

Because of the way income taxes are calculated, the backwards algebra is a bit complex. (Please see Attachment 9.) To make that process more understandable, it's helpful to break the calculation into three pieces. Using "T" as an abbreviation for the utility's corporate income tax percent, there is one block of numbers that has no tax adjustment, a second block that is multiplied by 1 / (1-T), and a third block that is multiplied by T / (1-T).

Most dollars are in the first block. That block includes all the non-tax expenses, as well as credits for Other Retail Revenue and Other Operating Revenue.

The 1 / (1-T) block consists of "grossed up" return. E.g., suppose $100 of return was needed. If the corporate tax rate were 40%, then $100 x 1 / (1 - .40), or $166.67 would need to be initially collected. After 40% was paid to income taxes, there would indeed be $100 left over.

The T / (1-T) block contains tax additions and deductions. E.g., book depreciation is an addition, while taxable depreciation is a deduction. If, as is normally the case, tax depreciation exceeded book depreciation, the net amount would be a tax credit. Suppose a net depreciation credit of $100 exists. Continuing the previous example, the $100 credit would avoid the tax payment of $66.67 out of the total $166.67. (And $100 x .40 / (1 - .40) does equal $66.67.) Therefore, the revenue requirement would only be $100. $100 x .40, or $40 would still go to income taxes, resulting in a preliminary net of $60. But because of the $100 depreciation tax credit, the utility could avoid writing the associated $40 tax check. That money could be added to the $60, providing a total of $100 to investors.

(Note that for accounting convenience, the 1 / (1-T) block grosses up all return revenue – not just return to shareholders (which really is taxable), but also debt (which is not taxable). However, since interest payments are tax deductible, the T / (1-T) block offsets the 1 / (1-T) impact on interest.)

V. Test Year Cost Development

The Company has a data gathering process that takes the following NSP (Minn) Company plant and plant-related data collected from the various departments and categorizes them into the functional use level of detail required for input into the CCOSS.

1. Electric Plant in Service (beginning and end of study period)
2. Accumulated provision for Depreciation of Plant in service (beginning and end of study period)
3. Accumulated Deferred Income Taxes (beginning and end of study period)
4. Construction Work in Progress
5. Book Depreciation
6. Property and Real Estate Taxes
7. Provision for Deferred Income Taxes
8. Investment Tax Credit: Flow-Through and Generated (this has been almost completely phased out)
9. Tax Deductions

In general, the system is developed from the computerized plant and depreciation records of the Company. The "plant in service" and "depreciation" expenses are identified by account and asset location numbers. Through the use of property aging records (age distributions of surviving plant in service by asset location) the remaining plant related items are developed from these account and asset location numbers. The input data that becomes available according to functional class total (such as production plant, transmission plant and distribution plant) and, in the case of budgeted data, according to funding project are prorated to the respective functional use designations through simulation processes giving effect to vintage distribution, appropriate depreciation methods, rates and procedures. This is accomplished in an automated mode by applying a series of allocation factors against plant data, the source information being supplied by various departments of the Company.

The balance of the plant and expense items in the cost study are functionalized primarily based upon projections of historical relationships and analyses and Federal Energy Regulatory Commission (FERC) or Company budgeting information. For example, operations and maintenance expenses are budgeted by JDE business unit, JDE object account and JDE subledger and mapped to FERC account for a test year cost study period.

Within the production function, the expenses of fuel, purchased power, and sales to non-associated utilities are obtained from the Company's electric production expense budget, interchange expense from the Company's Interchange Agreement between NSP's Minnesota and Wisconsin Companies, and other production expenses from the FERC budget. Transmission expense is determined by historical analysis and the FERC budget. Distribution O&M, customer accounting, customer service information, administrative and general definitions of expenses are determined from the FERC budget. Labor expenses also are captured from the FERC budget.

Other administrative and general O&M expenses such as property insurance, pensions and benefits, injuries and claims, rents and maintenance and regulatory expense are determined from the Company's budget.

Similarly, electric plant held for future use, unamortized rate case expense, fuel inventory, materials and supplies, prepayments, other operating revenues, extraordinary property losses and deferred costs charged to operating expenses are derived based upon the projection of historical cost relationships and corporate or FERC budgeting information.

Nuclear fuel consumed is determined from computer modeling of nuclear plant operations and the Company's production expense budget. Functionalization of Allowance for Funds Used During Construction (AFC) is developed in the FPIS.

The Company's test year costs explained above are entered into the Jurisdictional Cost of Service Study supported by the Company's Revenue Requirement Department. This study allocates or assigns the total Company costs to the appropriate jurisdiction. The resultant jurisdictional costs are entered into the CCOSS, which then allocates or assigns the jurisdictional costs to customer classes.

VI. FUNCTIONAL USE CATEGORIES BY FUNCTIONAL CLASS

Jurisdiction Functional Use

NOTE: Each of the following categories is applied to Minnesota, South Dakota, North Dakota and Wholesale jurisdictions.

Functional Class	Plant and Plant-Related Item Data	FERC Account
Production		310-346, 120.1 – 120.5
1. Fossil Plants	Steam	
2. Nuclear Plants	Nuclear Plant	
3. Other Plants	Other	
4. Hydro Plants	Hydro	
5. Nuclear Fuel	Nuclear Fuel	
Transmission		350-359

6. Transmission Lines: Transmission lines are classified as transmission based primarily on voltage level but also following the guidelines established in the Minnesota Cost Separation Filing (Docket No. E-

999/CI-99-1261). The Minnesota Commission determined that the guidelines and principals established in the Cost Separation Filing were consistent with the FERC 7 Factor Test.

7. Transmission Substations: Substations are functionalized as generation step-up, transmission, or distribution based on the principals and guidelines established in the Minnesota Cost Separation Filing. The Minnesota Commission determined that the guidelines and principals established in the Cost Separation Filing were consistent with the FERC 7 Factor Test

Distribution 360-373
8. Distribution Substations: Substations are functionalized as generation step-up, transmission, or distribution based on the principals and guidelines established in the Minnesota Cost Separation Filing. The Minnesota Commission determined that the guidelines and principals established in the Cost Separation Filing were consistent with the FERC 7 Factor Test

9. Distribution Mass Property: Overhead Lines, Underground Lines, Transformers and Capacitors, Services, Meters, Installations on Customer Premises, Leased Property on Customer Premises, and Street Lighting

General 389-399
10. General - All Tools and Equipment, Supervision and Data Retrieval, Buildings and Furniture, Motor Vehicle & Data Processing, and Research and Development

Common 301, Portions of 389-398
11. Common - Other than Transportation & Data Processing; Motor Vehicle & Data Processing

VII. FUNCTIONAL USE CATEGORIES FOR TRANSMISSION PLANT AND DISTRIBUTION SUBSTATIONS AND PLANT RELATED ITEMS
(FERC ACCOUNT NO.S 360-363)

A. Generation Step-Up
1. Substation facilities at generating stations that are utilized to connect the generators to the transmission system (including step-up transformers).
2. Substation equipment necessary for the operation of the generation station.
3. Transmission investment between generator and plant substation bus.

B. Bulk Transmission
1. Transmission lines operating as part of a loop or grid. (This category includes all transmission lines even if the line is a radial line or tap serving only a distribution substation or serving a particular customer or class of customer (except leased facilities).
2. Transmission Substations - facilities operating as part of a loop or grid.
3. Distribution Substations - facilities operating as part of a loop or grid. (This category will not include facilities at distribution substations if such a facility is only a high side bus tie breaker(s) or switch(s) between two distribution transformers or if such a facility is a switch(s) installed solely because the distribution substation is located there.)
4. Capacitors installed on transmission lines or installed on the high voltage side of a substation power transformer.

B. Distribution (600v-13.8kV) (most 23kV-34.5kV)
1. Distribution facilities in distribution substations.
2. Distribution facilities in transmission substations.
3. Distribution lines from 600 volts to 13.8kv.
4. 23kV and 34.5kV lines which do not operate as part of a subnetwork but serve as distribution primary.

5. Capacitors installed on distribution lines.
6. Capacitors installed on the low-voltage side of the power transformer(s) at distribution substations.

C. Direct Assignment
1. Substations where the entire substation, or a substantial portion of the substation, is solely devoted to a particular customer (investments of less than $100,000 will not be considered.)
2. Distribution Substations - substations and low-voltage equipment that supply both NSP retail customers and also a wholesale customer(s). (A percentage of such facilities is directly assigned to the wholesale customers(s) based on peak demand.)

VIII. CLASSIFICATION OF DISTRIBUTION MASS PROPERTY PLANT FUNCTIONAL USE ACCOUNTS

Overhead Lines (FERC Account No. ls 364 & 365)
The assignment of overhead conductors and poles investment to primary and secondary voltage levels, and street and area lighting was accomplished through the use of industry adopted engineering estimates.

The customer and capacity component classification of the primary and secondary voltage functions were developed using the 'minimum size' method for determining customer/ capacity components of distribution facilities. This method is discussed in the Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners (NARUC) in 1992.

Underground Lines (FERC Account No.'s 366 & 3671
The assignment of underground conductors and conduits investment to primary and secondary voltage levels was obtained from Company plant accounting records for underground cables and conduit (FERC Account No.'s 366 and 367).

The customer and capacity component classification of the primary and secondary voltage functions of these underground cables and conduits were developed using the 'minimum size, method for determining customer/capacity components of distribution facilities. This method is discussed in the Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners (NARUC) in 1992.

Line Transformers (FERC Account No. 368)
The assignment of line transformer investment to primary and secondary voltage levels was obtained from plant accounting records. Those records detailed the account by such items as line transformers, vault transformers, pad mounted transformers, auto transformers, regulators, and capacitors. The investments in capacitors, regulators and auto transformers were assigned to the primary function and the balance of the account was assigned to the secondary function.

The secondary function was further divided into capacity and customer components. Vault transformers were assigned as 100% capacity while pad mounted and line transformers were separated between capacity and customer components on the basis of the minimum system concept as discussed under overhead and underground lines. The results of this analysis are summarized below:

Services (FERC Account No. 3691
The Company maintains Account No. 369 for overhead services by size and type of line and associated quantity of each type of service installation. The entire account was considered related to the secondary function.

The division of overhead services into capacity and customer components was made based on a historical relationship using the minimum system concept discussed under overhead lines. Underground services were separated based on the same percentages developed for overhead services. The following relationships were developed from this analysis:

General Plant (FERC Account No- Is 389-399)
Facilities common to all electric functions (i.e. production, transmission, distribution)

Electric Common Plant (FERC Account No. Is 301, 389-399)
The electric portion of facilities common to both utilities, electric and gas

IX. STRATIFICATION

Base Load/Peaking Stratification
Production plant investment is stratified (split) into two components: capacity-related (peaking) and energy-related (base load).

The method used to stratify production plant investment compares the average insurance replacement cost per MW of capacity of the various sources of capacity. These sources consist of nuclear, fossil steam, hydro, and gas turbine or diesel generation. The least expensive plant source, gas turbine or diesel peaking generation, is compared to the other sources. The percentage amount that peaking represents of other capacity sources is used to determine the peaking component of each capacity source.

This method recognizes the dual role of all capacity sources in supplying both energy and demand requirements. In other words, only that portion of a generating plant over the cost of a peaking plant is attributed to the energy-related (base load) function. This results in nuclear and fossil investment costs are stratified to both base load and peaking components. These plants provide inexpensive energy and, at the same time, contribute towards meeting the peak load requirements.

This stratification method splits production plant investment as follows:

Production Type	% Base Load	% Peaking
Hydro	75.9	24.1
Nuclear	84.4	15.6
Steam Fossil	73.7	26.3
Gas Turbine & Diesels	0.0	100.0

The stratification methodology is also applied to the demand-related expenses associated with purchased power agreements. Each purchased power agreement is analyzed as to which capacity source it most closely represents. These expenses are then stratified using the appropriate production type percentages noted above.

Summer Peaking/Winter Peaking Functional Use Categories
The capacity-related component of production plant investment is further separated into summer and winter seasonal costing periods. This separation recognizes the costs incurred by customers in relationship to their loads in these seasons. The portion of the capacity-related component dedicated to serving a seasonal function is computed by applying a seasonal demand-weighting factor to peaking plant investment. The weighting factor is derived from test year monthly system peak demands, which have been reduced by the annual average demand. The four summer months and eight winter months are specified and averaged to determine each season's portion of the averaged annual total.

The current factor used in the Class Cost Study weighs 74.54% of peaking investment to the summer period and 25.46% to the winter period.

X. ALLOCATOR DESCRIPTIONS

In the table below, the Code column contains the allocator codes actually listed in the CCOSS printout. The Description column mostly describes what the allocator is, and the Derivation column mostly describes how the allocator was created; however, there is some overlap between these two columns. The E/I column tells whether an allocator is external or internal. (An external allocator is one that was prepared outside of the CCOSS. An internal allocator is created within the CCOSS by combining the results of external allocators and / or other internal allocators.) The Components column indicate which billing component(s) and unbundled business unit(s) the allocator applies to. The letters in this column correspond to the codes shown in Attachment 7. Nearly every line of this table is a normal allocator that first spreads dollars to class and then spreads each class amount to billing and unbundled components. But a few of the "typed-in" revenue amounts, such as R01, only spread dollars to class. And there are also a pair of "column allocators" (BASE and R02). These allocators are only used after dollars have already been spread to class. Then they spread the results to the component column. Such two-stage allocations are indicated in the Alloc column of the CCOSS with a semi-colon (e.g., "R01;R02"). Please see Attachment 10 for an overview of the Company's electrical system and how the allocators fit into it.

Code	Description	Derivation	E/I	Components
BASE (col)	Rate Base column allocator	Component allocators for each subclass add to 100%	Int	BSW-NF-T-UPC-VE
C10	C11 less duplicate service customers	C11 less automatic protective lighting and load management customers	Ext	V
C11	Average monthly customers	Forecasted annual bills / 12	Ext	V
C11P10	Average of customer percents and production plant percents	C11PI0 = (C11%+P10%)/2	Int	BSW-E
C11WA	Weighted customer accounting expenses	C11 X C11WAF	Ext	E
C11WAF	Customer accounting weighting factors	Accounting costs for a residential customer are set to 1.0. Other classes are defined relative to residential. E.g., if a class were three times costlier, its factor would be 3.0.	Ext	E
C12	C11 with adjusted street lighting customer count	Reflects actual number of meters	Ext	V
C12WM	Weighted meter investment	C12 X C12WMF	Ext	V
C12WMF	Average meter cost for each customer type		Ext	V
C61PS	Average monthly customers served at primary or secondary voltage	C11 less transmission transformed and transmission voltage customers	Ext	V
C62NL	Adjusted average monthly secondary voltage customers	C62Sec less street lighting and C&I underground customers	Ext	V
C62Sec	Average monthly customers served at secondary voltage	C61PS less primary voltage customers	Ext	V

D100E0	100 percent Production Level Demands and 0 percent Energy at Generation Level weighted by hourly price	D100E0 = (1.0000 x D10C)+(0.000 x E8760). The demand portion is further split between Summer and Winter based on D10C; the energy portion is already split between on-peak and off-peak because E8760 is split that way. Weighting based on economic development energy times any excess energy charge (Gen Svc secondary voltage energy – marginal energy cost) vs economic development demand times the average annual demand charge (Gen Svc secondary voltage demand, 4/12 summer and 8/12 winter)	Int	SW
D10C	Weighted Average of Class Contributions to Summer and Winter Peaks - Production Level	Allocator equals (D10W% plus (D10S% times 2.9278)) divided by (1 + 2.9278); 2.9278 is the ratio obtained by taking the average summer and winter system peaks, subtracting the average annual load and dividing the two results.	Int	SW
D10S	Class contribution to Summer System Peak, from 2005 Demand Study		Ext	S
D10T	Weighted Average of Class Contributions to Summer and Winter Peaks - Transmission Level	Allocator equals (D10W% plus (D10S% times 1.3553)) divided by (1 + 1.3553); 1.3553 is the ratio of the average summer and winter system peaks.	Ext	T
D10W	Class contribution to Winter System Peak, from 2005 Demand Study		Ext	W
D20	E20, but treated as a demand allocator	(Only used if E20 is used)	Ext	B
D60Sub	Class-coincident peak less transmission-level demand		Ext	U
D62E38	62 percent Production Level Demands and 38 percent Energy at Generation Level weighted by hourly price	D62E38 = (.6229 x D10C)+(.3771 x E8760). The demand portion is further split between Summer and Winter based on D10C; the energy portion is already split between on-peak and off-peak because E8760 is split that way. Weighting is based on a CIP allocation of program costs.	Int	SW-NF

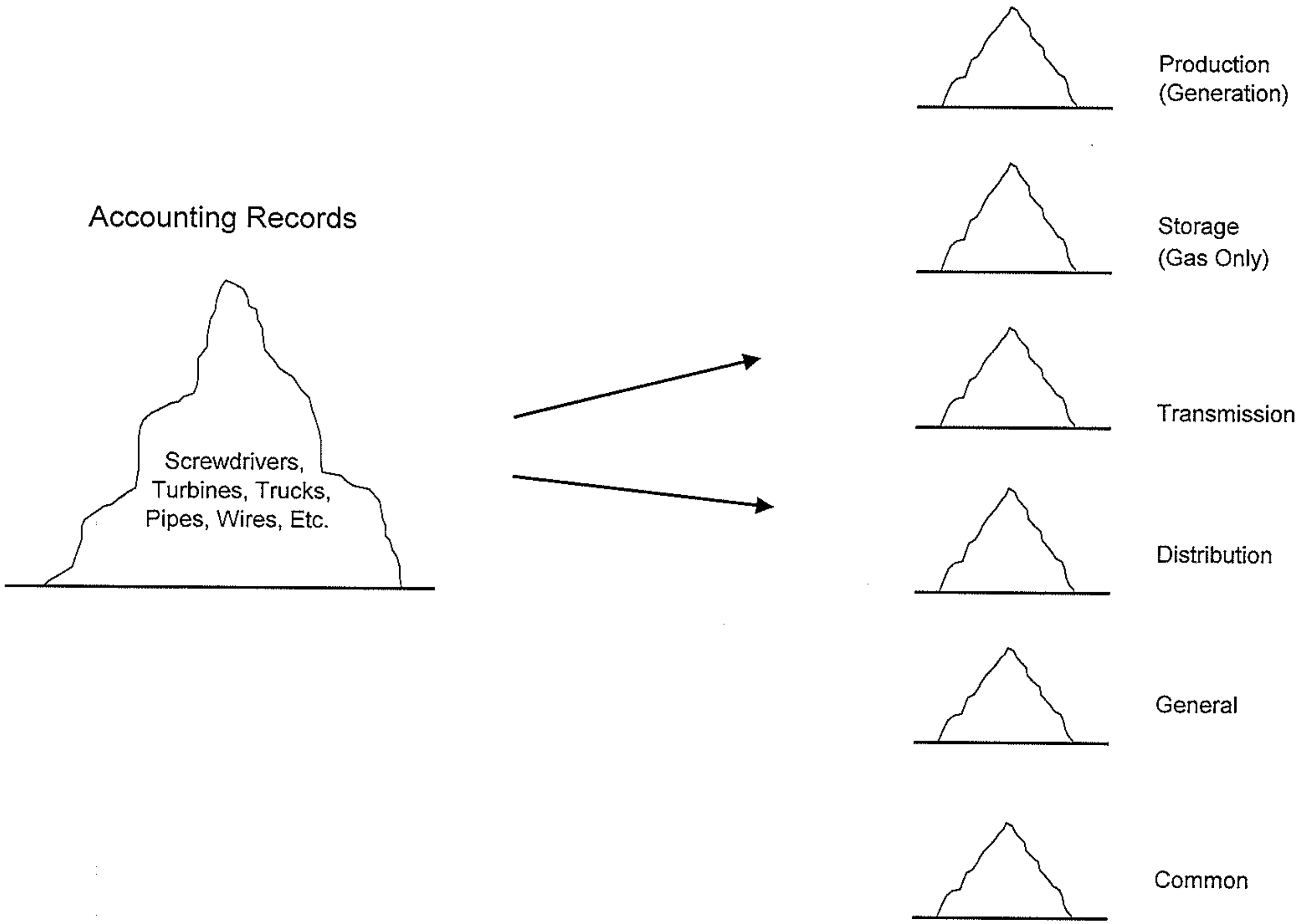
D61PS	Class-coincident peak for primary and secondary voltage customers	D60Sub less transmission transformed demands and customer demand served by minimum distribution system, with reduced Residential With Space Heating demand to reflect that their summer peak is less than their winter peak	Ext	P
D62NLL	Secondary voltage demand less lighting	Non-coincident (or "customer peak") demand for secondary voltage customers, less the following: street lighting, area lighting and C&I customers served underground	Ext	C
D62SecL	Average of class-coincident peak, secondary voltage percents and non-coincident secondary voltage percents	First define D62Sec as equal to D61PS, less primary customers. Then for each secondary class, D62SecL equals the average of D62Sec percent and non-coincident (or "customer peak"), secondary voltage percent.	Ext	C
D8760	E8760, but treated as a demand allocator		Ext	B
DASL	Street lighting demands for overhead lines	Split further among company-owned, customer-owned and area protective lighting	Ext	V
Dir Assign	A direct assignment of costs or revenues to a specific class or classes.		Ext	Various
E10	Energy (MWH) at Generation Level (only used for the preparation of E20)	Budgeted class sales at the meter, divided by class loss factor, to get sales at the generator	Ext	NF
E11	Class annual on-peak percentages	Load Research department	Ext	N
E20	Energy (MWH) at generation, with annual on-peak sales weighted to reflect higher on-peak fuel costs (This method was used in 1993 and was reviewed as an option for this case.)	E20 = On-Peak + Off-Peak, where On-Peak = E10 X E11 X 1.672 and Off- Peak = E10 X (1-E11). Note: 1.672 = ratio of on-peak to off-peak annual marginal energy costs	Ext	NF
E8760	Energy (MWH) at generation, with hourly on-peak sales weighted to reflect higher on-peak fuel costs (This was the filed energy allocator, in lieu of the E20 method.)	The hourly on-peak sales ratio for each class is weighted by the hourly marginal energy cost. (There are 8,760 hours per year.)	Ext	NF

LABOR(S)	LABOR (and LABORS) reflect total labor costs on page 12	LABORS equals all labor costs except Admin and General. But LABORS is then used to allocate Admin and General, and the result is added to LABORS to derive LABOR. Thus the two allocators are actually identical.	Int	BSW-NF-T-UPC-VE
NEPIS	Net Electric Plant in Service (bottom of pg 6, prior to any TBT consideration)	Electric plant in service less accumulated provision for depreciation	Int	BSW-T-UPC-V
ORDREV	Typed-in Ordered Revenues	PROREV is used for the Proposed CCOSS; ORDER is used for the Ordered CCOSS	Ext	BSW-NF-T-UPC-VE
OXDTS	All Distribution O&M Expense, except Supervision and Engineering, Customer Install and Miscellaneous	Lines 2 thru 7, 9 and 11 of page 8. Note: Supervision & Engineering must be excluded to avoid an infinite loop in the spreadsheet.	Int	BSW-T-UPC-V
OXOPD	Other Production: Total Capacity costs	Other Prod: Peaking + Base Load (line 38 of page 7)	Int	BSW
OXTS	Relevant O&M costs	All O&M costs except Regulatory Expense and any A&G costs that will be allocated on OXTS (all expenses on the bottom of page 7 and all of page 8, except as noted)	Int	BSW-NF-T-UPC-VE
P10	Production Plant	Total production costs , on line 6 of page 4	Int	BSW
P5161A	Total Generation Set-Up	Tran Gener Step Up (line 9 of page 4) + Distrib Substn Step Up (line 14 of page 4)	Int	BSW
P61	Distribution Plant: Substations	Substations (line 18, page 4)	Int	BSW-T-U
P68	Distribution Plant: Line Transformers	Primary & secondary; capacity & customer (line 37 of page 4)	Int	PC-V
P69	Distribution Plant: Services	Secondary; capacity & customer (line 40 of page 4)	Int	C-V
P73	Typed-in Street Lighting	Line 42 of page 4	Ext	V
POL	Distribution Plant: Overhead Lines	Primary, secondary & street lighting; capacity & customer (line 26 of page 4)	Int	PC-V
PROREV	Typed-in Proposed Revenues	PROREV is used for the Proposed CCOSS; ORDER is used for the Ordered CCOSS	Ext	BSW-NF-T-UPC-VE
PT0	Total Real Estate & Property Taxes	Line 50 of page 9	Int	BSW-T-UPC-V
PTD	Production + Transmission + Distribution Plant	Lines 6, 13 and 43 of page 4	Int	BSW-T-UPC-V
PUL	Distribution Plant: Underground Lines	Primary & secondary; capacity & customer (line 33 of page 4)	Int	PC-V

R01	Typed in Present Revenues	Revenues generated from present rate design	Ext	BSW-NF-T-UPC-VE
R02 (col)	All pre-tax operating expenses except for items allocated to component by R02	Component allocators for each subclass add to 100%	Int	BSW-NF-T-UPC-VE
R16C	Typed-in Late Pay Charges		Ext	BSW-NF-T-UPC-VE
R16D	Typed-in Present Misc Service Charges		Ext	V
R16DD	Typed-in Proposed Increased Misc Svc Charges		Ext	V
RTBASE	Total Rate Base (see also "BASE")	Line 36 of page 6	Int	BSW-NF-T-UPC-VE
STRATH	Production plant stratification study, for hydro		Ext	BSW
TD	Transmission + Distribution	Lines 13 and 43 of page 4	Int	BSW-T-UPC-V
ZDTS	All Labor Distribution expense except Supervision and Engineering	All of lines 27 thru 47 on page 12, except lines 33 and 40	Int	BSW-T-UPC-V

Plant Functionalization

By FERC Category



Rate Case - Cost Information Flow

Functionalized Accounting Costs

Desc	Costs
Produc	
Summ Pk	100
Winter Pk	200
Base	300
Total	600
Trans	
Step Up	
Bulk	
Direct	
Total	
Distrib	
Subs	
Overhead	

JCOSS

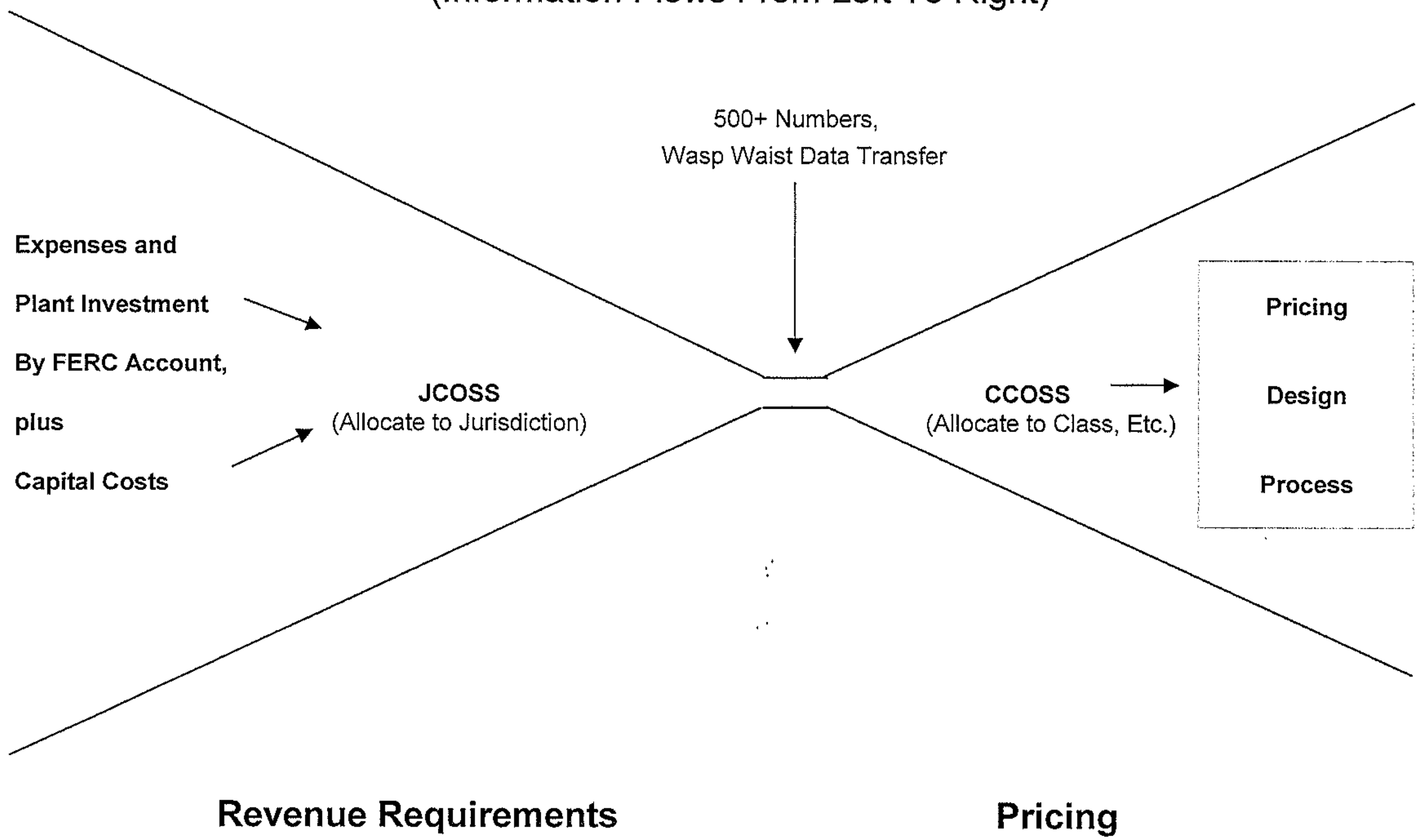
Desc	Alloc	Total	Mn	ND	SD
Produc					
Summ Pk	D10	100	70	20	10
Winter Pk	D15	200	150	30	20
Base	D20	300	170	40	90
Total		600	390	90	120
Trans					
Step Up					
Bulk					
Direct					
Total					
Distrib					
Subs					
Overhead					

CCOSS

Desc	Alloc	Mn	Res W/	Res W/o	(Other) (Classes)
Produc					
Summ Pk	D10S	70	2	11	....
Winter Pk	D10W	150	5	28	....
Base	D8760	170	22	33	....
Total		390	29	72	....
Trans					
Step Up					
Bulk					
Direct					
Total					
Distrib					
Subs					
Overhead					

Regulated Cost Allocation and Pricing Process

(Information Flows From Left To Right)



CCOSS Overview

In a rate case, a utility is allowed to recover all approved expenses, plus a reaonable return on net investment.

RATE BASE (Balance Sheet)

Original Plant in Service
- Accum Depreciation
+ & - Misc. Adjustments
Rate Base

INCOME STATEMENT

Revenue
- Oper & Maint Expen
- Bk Deprec, Prop Tax, Etc.
- Income Tax
Return $

Return $ / Rate Base = % Return

CCOSS - Top View

Detail of the 16 Print Pages

Summary	
Rate Base; Income Statement (Pres vs Prop/Ord Return)	1
Equal Return Rev Components	2
Prop/Order Return Rev Components	3

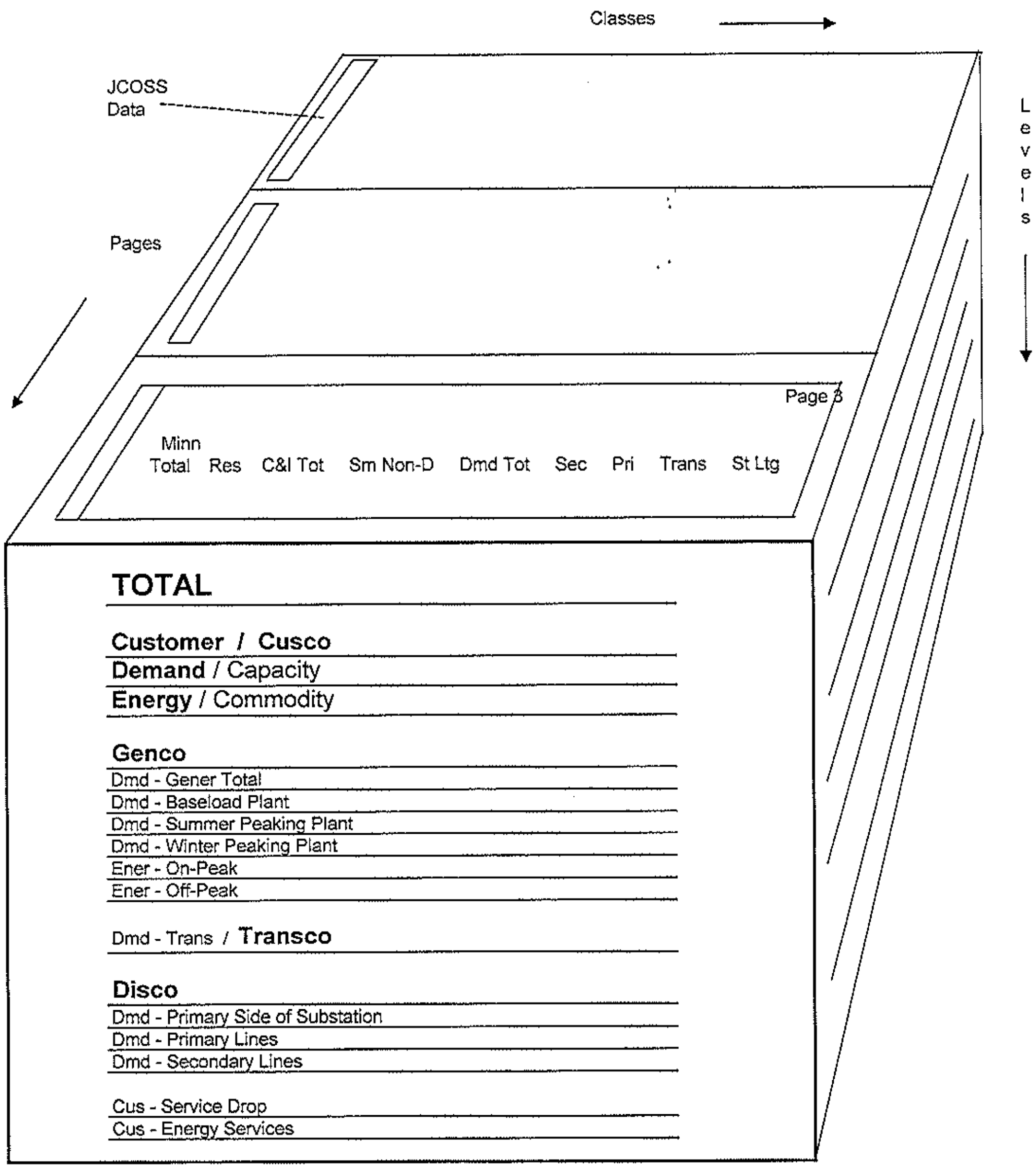
Rate Base	
Original Plant in Service	4
- Accumulated Depreciation - Subtractions (Accum Deferred Income Tax)	5
+ Additions (Construction Work in Progress & Misc) Rate Base	6

Income Stmt	
Present & Proposed/Ordered Revenue - O&M (Production, Transmission) [Pg 1 of 2]	7
- O&M (Distributiono & Misc) [Pg 2 of 2]	8
- Book Depreciation - Property Taxes	9
- Prov For Defer IT - Current Inv Tax Credit = Oper Inc Before Inc Tax	10
Tax Depreciation + And - Adjustments ===> Income Tax Oper Inc - Inc Tax = Pres & Prop/Order Return	11

Misc Calcs	
Allow For Funds Used During Construction Labor Allocator	12
Pres, Prop/Ord & Equal Rev Components	13

Allocators	
Internal Allocators	14
External Allocators	15
Constants	16

CCOSS - 3-D View



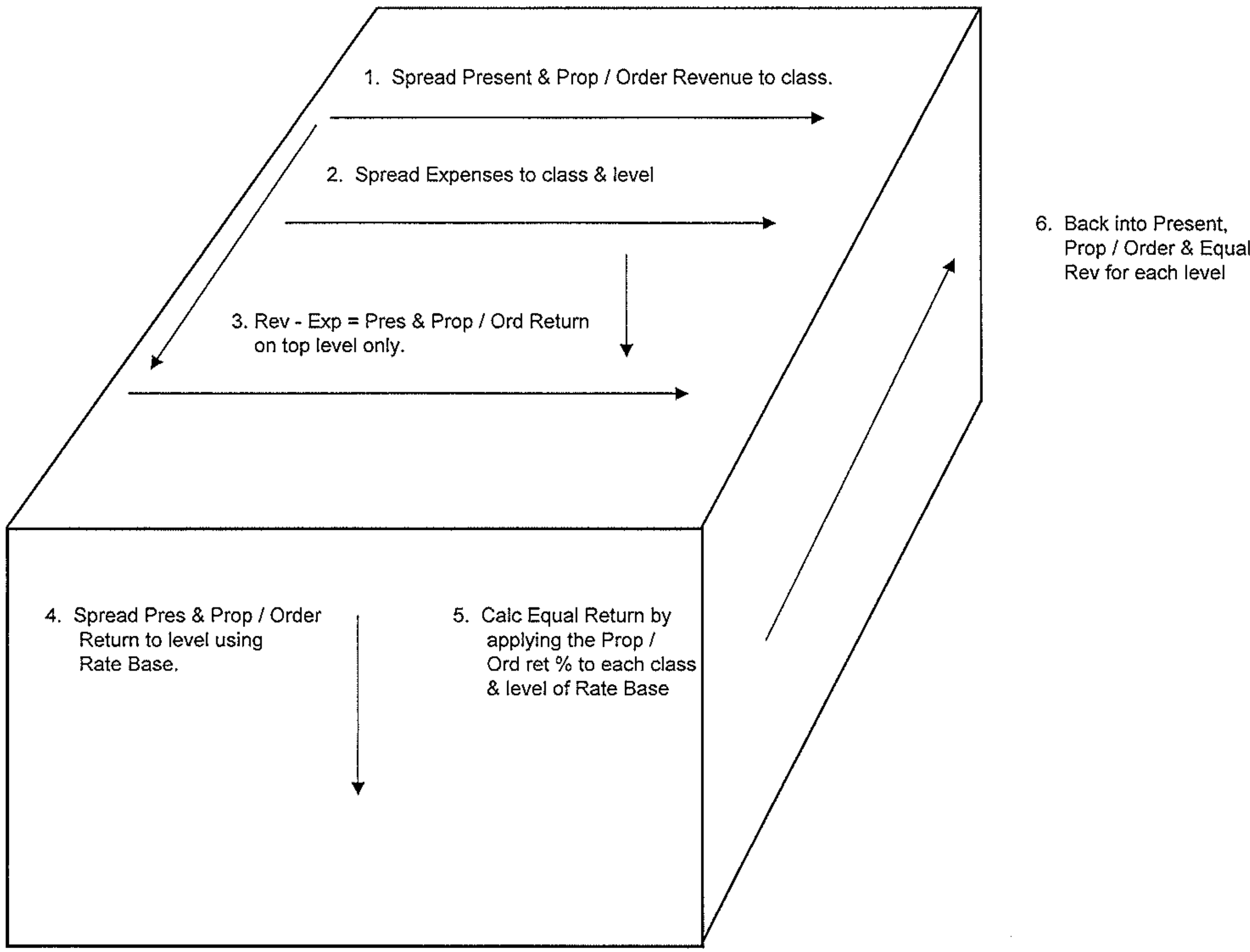
Unbundled CCOSS Totaling Rules

Unbundled Business Units

Billing Components

Total	Genco	Transco	Disco	Cusco
Customer				Service Drops (**V**) Energy Svcs (**E**)
Demand	(Gen Demd) Baseload Plant (**B**) Summer Peak Plant (**S**) Winter Peak Plant (**W**)	Transmission (**T**)	Substation (**U**) Primary Lines (**P**) Secondary Lines (**C**)	
Energy	On-Peak Energy (**N**) Off-Peak Energy (**F**)			

CCOSS - Backwards Rev Calc



Backward Retail Revenue Requirement

Backwards Revenue Formula

Retail Rev Reqt = Expenses (including Other Op Rev credit)

+ (Return on Equity x Rate Base) x 1 / (1-T)
+ (Tax Additions - Tax Subtractions) x T / (1-T)
- AFUDC

Expenses = Oper&Maint + Book Deprec + RI Est & Property Tax + Payroll Taxes + Prov For Defer Inc Tax + Net Investment Tax Credit - Other Retail Revenue - Other Operating Revenue

Tax Additions = Book Deprecitaion + Deferred Inc Tax + Net Inv Tax Credit + Other Misc Expenses

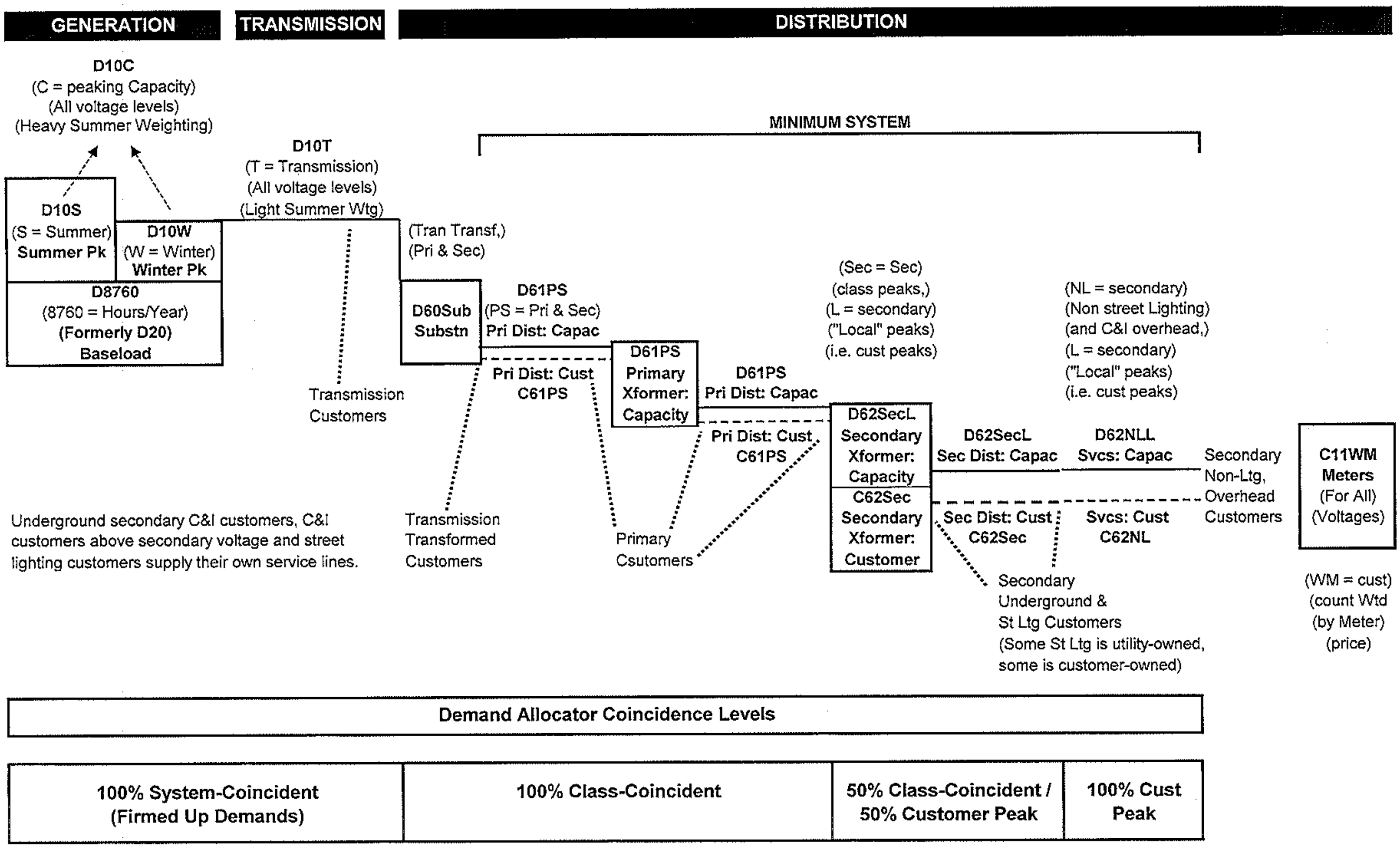
Tax Subtractions = Tax Depreciation + Interest Expense + Other Tax Timing Differences

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
Guide to Class Cost of Service Study - Attachments

Case No. ____________
Exhibit No. ____________(PJZ-1)
Schedule 3; Part 2 of 2
Attachment 10 of 10

ELECTRIC SYSTEM ALLOCATORS

Height on the page roughly equates to voltage level



Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
Compliance Class Cost of Service Study Results ($000)

Case No. PU-07-_______
Exhibit No. _____(PJZ-1)
Schedule 4

Summary

UNADJUSTED	Total	Residential	Small C&I Non-Demand	Small C&I Demand	Large C&I Demand	Muni	Street Ltg
Total Oper Revenues	167,714	65,647	11,813	52,214	35,271	944	1,825
Incr Late Pay & Misc Chrg	78	37	5	23	11	0	1
Retail Revenue Reqt	167,636	65,610	11,808	52,191	35,260	944	1,824
Present Rates	147,179	57,724	10,375	46,569	29,753	878	1,881
Deficiency	20,457	7,886	1,433	5,622	5,507	66	(56)
Defic / Pres	13.9%	13.7%	13.8%	12.1%	18.5%	7.5%	-3.0%
Ratio: Class % / Total %	**1.00**	**0.98**	**0.99**	**0.87**	**1.33**	**0.54**	**-0.22**

ADJUSTED							
Total Oper Revenues	171,498	66,889	12,090	53,593	36,121	969	1,835
Incr Late Pay & Misc Chrg	78	37	5	23	11	0	1
Retail Revenue Reqt	171,420	66,852	12,085	53,570	36,110	969	1,834
Present Rates	150,963	58,141	10,394	46,628	33,042	878	1,881
Deficiency	20,457	8,711	1,692	6,942	3,068	91	(47)
Defic / Adj Pres	13.6%	15.0%	16.3%	14.9%	9.3%	10.4%	-2.5%
Ratio: Class % / Total %	**1.00**	**1.11**	**1.20**	**1.10**	**0.69**	**0.76**	**-0.18**

PROPOSED							
Proposed Rates	167,636	65,968	11,915	52,797	34,025	1,050	1,880
Prop - Pres	20,457	8,245	1,541	6,228	4,272	172	0
Difference / Pres	13.9%	14.3%	14.9%	13.4%	14.4%	19.6%	0.0%
Ratio: Class % / Total %	**1.00**	**1.03**	**1.07**	**0.96**	**1.03**	**1.41**	**0.00**

Rate Base

		Alloc	1=2+6+9+10	2=3 to 5	12=13 to 15	13	14	15	16=17 to 20	17	18	19	20	31=32+33	34=35 to 37
	Plant In Service		ND	Res Tot	Sm Tot	Sm Non-D	Second	Primary	Lg Tot	Second	Primary	Trans	Interrupt	Muni Tot	Ltg Tot
1	Production		356,704	123,131	143,201	23,732	117,604	1,866	86,469	18,852	1,241	0	66,376	2,083	1,819
2	Transmission		87,557	33,070	41,900	6,857	34,509	534	11,559	5,104	316	0	6,139	644	383
3	Distribution		124,202	71,349	34,145	9,343	24,552	251	14,172	3,058	107	0	11,007	647	3,888
4	General		14,538	5,819	5,607	1,021	4,518	68	2,869	691	43	0	2,136	86	156
5	Common		24,338	9,742	9,387	1,710	7,564	113	4,804	1,157	71	0	3,576	144	261
6	TBT Invest		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Total		607,339	243,112	234,240	42,662	188,746	2,832	119,874	28,862	1,778	0	89,234	3,606	6,507
	Depreciation Reserve														
8	Production		234,339	81,339	93,121	15,413	76,490	1,218	57,272	12,391	822	0	44,059	1,347	1,260
9	Transmission		29,941	11,286	14,292	2,340	11,770	182	4,012	1,742	108	0	2,162	220	131
10	Distribution		48,239	27,305	13,027	3,575	9,357	96	5,399	1,163	40	0	4,196	248	2,259
11	General		6,955	2,784	2,682	489	2,161	32	1,373	331	20	0	1,022	41	75
12	Common		13,692	5,481	5,281	962	4,255	64	2,702	651	40	0	2,012	81	147
13	Total		333,166	128,195	128,403	22,777	104,033	1,592	70,759	16,278	1,030	0	53,451	1,937	3,872
14	**Net Plant In Service**		274,173	114,917	105,837	19,885	84,713	1,239	49,115	12,584	747	0	35,783	1,669	2,635
	Deductions														
15	Accum Defer Inc Tax		40,717	18,150	15,307	2,962	12,175	170	6,802	1,777	101	0	4,924	248	209
	Additions														
16	Constr Work In Progress		4,802	1,663	2,021	338	1,657	26	1,066	255	16	0	796	30	22
17	Fuel Inventory		2,358	828	917	151	754	12	586	125	8	0	453	13	14
18	Materials & Supplies		5,412	2,035	2,125	371	1,727	27	1,175	270	17	0	888	32	45
19	Prepayments		1,864	781	720	135	576	8	334	86	5	0	243	11	18
20	Non-Plant Assets & Liab		(6,928)	(2,999)	(2,519)	(539)	(1,950)	(30)	(1,272)	(292)	(18)	0	(962)	(36)	(102)
21	Working Cash		1,136	489	421	82	334	5	203	49	3	0	151	7	16
22	Total		8,644	2,798	3,684	539	3,097	48	2,092	492	31	0	1,569	57	13
23	**Rate Base**		242,100	99,564	94,214	17,462	75,635	1,117	44,405	11,300	678	0	32,427	1,478	2,439

Income Statement

		ND	Res Tot	Sm Tot	Sm Non-D	Second	Primary	Lg Tot	Second	Primary	Trans	Interrupt	Muni Tot	Ltg Tot
24A	**Tot Oper Rev - Pres**	186,704	71,880	72,850	13,018	58,922	909	38,749	8,946	604	0	29,199	1,108	2,117
24B	**Tot Oper Rev - Prop**	207,239	80,162	80,647	14,564	65,090	992	43,031	9,866	664	0	32,501	1,281	2,117
25	Oper & Maint	148,725	55,802	57,417	10,257	46,429	731	33,340	7,434	490	0	25,416	822	1,344
26	Book Depr + IRS Int	19,160	7,659	7,361	1,346	5,926	89	3,758	902	55	0	2,801	114	269
27	Payroll Tax	1,310	567	476	102	369	6	241	55	3	0	182	7	19
28	Real Est & Prop Tax	5,763	2,483	2,134	417	1,692	24	1,028	250	14	0	764	34	84
29	Deferred Inc Taxes	1,738	552	850	138	701	12	338	105	7	0	226	13	(14)
30A	Present Income Tax	214	473	249	26	223	(1)	(687)	(111)	2	0	(578)	22	157
30B	Proposed Income Tax	8,270	3,722	3,308	633	2,643	32	993	250	25	0	717	90	157
31	Allow Funds Dur Const	0	0	0	0	0	0	0	0	0	0	0	0	0
32A	**Present Return**	9,794	4,345	4,363	732	3,583	48	732	311	32	0	389	96	258
32B	**Proposed Return**	22,273	9,378	9,102	1,672	7,331	98	3,335	870	69	0	2,395	201	258
33A	**Pres Ret on Rt Base**	4.05%	4.36%	4.63%	4.19%	4.74%	4.31%	1.65%	2.75%	4.75%	0.00%	1.20%	6.49%	10.59%
33B	**Prop Ret on Rt Base**	9.20%	9.42%	9.66%	9.57%	9.69%	8.82%	7.51%	7.70%	10.18%	0.00%	7.39%	13.58%	10.60%
34A	**Pres Ret on Common**	1.54%	2.15%	2.67%	1.82%	2.87%	2.04%	-3.09%	-0.96%	2.90%	0.00%	-3.96%	6.25%	14.18%
34B	**Prop Ret on Common**	11.49%	11.92%	12.38%	12.22%	12.45%	10.75%	8.23%	8.60%	13.39%	0.00%	7.99%	19.94%	14.19%

(Comm / Indus By Size)

PRES vs Equal Rev Reqts

			1=2+8+9+10	2=3 to 5	12=13 to 15	13	14	15	16=17 to 20	17	18	19	20	31=32+33	34=35 to 37
				0	0				0					0	0
	Total Retail Rev Reqt	Alloc	ND	Res Tot	Sm Tot	Sm Non-D	Second	Primary	Lg Tot	Second	Primary	Trans	Interrupt	Muni Tot	Ltg Tot
1	Equal Return On Rate Base		9.20%	9.20%	9.20%	9.20%	9.20%	9.20%	9.20%	9.20%	9.20%	9.20%	9.20%	9.20%	9.20%
2	Equalized Rev Reqt		167,636	65,610	63,998	11,808	51,399	791	35,260	8,045	514	0	26,701	944	1,824
3	Present Revenue		147,179	57,724	56,944	10,375	45,867	702	29,753	6,848	465	0	22,440	878	1,881
4	Revenue Deficiency		20,457	7,886	7,055	1,433	5,532	90	5,507	1,196	49	0	4,261	66	(56)
5	Deficiency / Present		13.90%	13.66%	12.39%	13.81%	12.06%	12.77%	18.51%	17.47%	10.64%	0.00%	18.99%	7.48%	-3.00%
6	Firmed Up Revenue		3,784	417	78	19	59	0	3,289	0	0	0	3,289	0	0
7	Interruptible Capacity Costs	D10C	3,784	1,242	1,657	277	1,359	21	850	199	12	0	639	25	10
8	Revenue Shift		0	824	1,579	259	1,300	21	(2,439)	199	12	0	(2,650)	25	10
9	Adj Equal Rev Reqt (Rows 2+7)		171,420	66,852	65,655	12,085	52,758	812	36,110	8,244	527	0	27,340	969	1,834
10	Adj Pres Rev (Rows 3+6)		150,963	58,141	57,021	10,394	45,926	702	33,042	6,848	465	0	25,729	878	1,881
11	Adj Revenue Deficiency		20,457	8,711	8,634	1,692	6,832	110	3,068	1,395	62	0	1,611	91	(47)
12	Adj Deficiency / Adj Present		13.55%	14.98%	15.14%	16.28%	14.88%	15.73%	9.28%	20.37%	13.27%	0.00%	6.26%	10.36%	-2.47%
	Customer Component														
13	Min Sys & Service Drop		11,707	8,958	1,572	1,154	402	16	171	(1)	1	0	172	29	976
14	Energy Services		5,437	4,271	1,089	736	351	2	53	1	0	0	52	0	23
15	Total Customer (Cusco)		17,144	13,230	2,661	1,890	753	18	224	(1)	1	0	224	29	1,000
16	Ave Monthly Customers		87,633	73,609	11,652	8,553	3,080	18	190	4	1	0	185	182	2,000
17	Svc Drop Reqt	$ / Mo / Cust	$11.13	$10.14	$11.24	$11.24	$10.88	$71.63	$75.04	($28.61)	$61.07	$0.00	$77.35	$13.18	$40.68
18	Ener Svcs Reqt	$ / Mo / Cust	$5.17	$4.84	$7.79	$7.17	$9.49	$9.49	$23.19	$14.15	$14.15	$0.00	$23.44	$0.21	$0.97
19	Total Reqt	$ / Mo / Cust	$16.30	$14.98	$19.03	$18.42	$20.37	$81.13	$98.23	($14.46)	$75.22	$0.00	$100.79	$13.39	$41.65
	Energy Component														
20	On Peak Rev Reqt		45,032	14,258	19,009	3,235	15,530	245	11,380	2,453	157	0	8,770	274	110
21	Off Peak Rev Reqt		38,232	14,941	13,378	2,112	11,084	183	9,337	1,959	140	0	7,238	189	386
22	Total Ener Rev Reqt		83,264	29,200	32,387	5,346	26,614	428	20,717	4,413	297	0	16,008	463	496
23	Annual Mwh Sales		2,217,924	782,202	836,541	134,951	690,197	11,393	568,703	119,144	8,335	0	441,224	11,761	18,717
24	On Pk Reqt	Mills / kWh	20.304	18.228	22.724	23.968	22.501	21.487	20.011	20.592	18.851	0.000	19.876	23.339	5.879
25	Off Pk Reqt	Mills / kWh	17.238	19.102	15.992	15.647	16.059	16.060	16.419	16.444	16.789	0.000	16.405	16.051	20.639
26	Total Reqt	Mills / kWh	37.541	37.330	38.716	39.615	38.559	37.547	36.429	37.036	35.640	0.000	36.280	39.390	26.518
	Demand Component														
27	Base Load Prod		21,888	7,678	8,514	1,405	6,996	112	5,445	1,160	78	0	4,207	122	130
28	Summer Peak Prod		15,564	4,702	7,153	1,179	5,883	90	3,599	862	52	0	2,685	110	0
29	Winter Peak Prod		5,250	2,123	1,965	347	1,593	25	1,079	235	15	0	829	29	55
30	Total Production		42,703	14,502	17,631	2,932	14,472	227	10,123	2,256	145	0	7,722	261	185
31	Transmission (Transco)		14,230	5,388	6,837	1,119	5,632	87	1,837	833	51	0	953	105	63
32	Primary Dist Subs		2,834	1,141	1,069	171	885	13	578	130	8	0	439	17	30
33	Prim Dist Lines		3,246	979	1,423	197	1,207	18	790	178	11	0	600	23	31
34	Second Dist. Trans		4,215	1,171	1,989	153	1,836	(0)	990	235	(0)	0	755	45	20
35	Total Distribution (Disco)		10,296	3,291	4,481	521	3,928	32	2,358	544	20	0	1,795	85	81
36	Total Demand Rev Reqt		67,228	23,181	28,950	4,571	24,032	346	14,318	3,633	216	0	10,469	451	328
37	Annual Billing kW		3,530,304	0	2,158,612	0	########	31,468	########	248,181	16,727	0	########	58,350	0
38	Base Rev Reqt	$ / kW	$0.00	$0.00	$3.94	$0.00	$3.29	$3.57	$4.15	$4.67	$4.67	$0.00	$4.01	$2.09	$0.00
39	Summer Rev Reqt	$ / kW	$0.00	$0.00	$3.31	$0.00	$2.77	$2.85	$2.74	$3.47	$3.13	$0.00	$2.56	$1.89	$0.00
40	Winter Rev Reqt	$ / kW	$0.00	$0.00	$0.91	$0.00	$0.75	$0.79	$0.82	$0.95	$0.90	$0.00	$0.79	$0.50	$0.00
41	Prod Rev Reqt	$ / kW	$0.00	$0.00	$8.17	$0.00	$6.80	$7.21	$7.71	$9.09	$8.69	$0.00	$7.37	$4.47	$0.00
42	Tran Rev Reqt	$ / kW	$0.00	$0.00	$3.17	$0.00	$2.65	$2.77	$1.40	$3.36	$3.08	$0.00	$0.91	$1.81	$0.00
43	Dist Rev Reqt	$ / kW	$0.00	$0.00	$2.08	$0.00	$1.85	$1.01	$1.80	$2.19	$1.17	$0.00	$1.71	$1.46	$0.00
44	Tot Dmd Rev Reqt		$0.00	$0.00	$13.41	$0.00	$11.30	$10.99	$10.90	$14.64	$12.94	$0.00	$9.99	$7.73	$0.00
45	Tot Dmd Rev Reqt	Mills / kWh	30.311	29.635	34.606	33.875	34.820	30.356	25.177	30.489	25.966	0.000	23.728	38.374	17.531
46	Summer Billing kW		1,222,164	0	729,982	0	719,060	10,922	470,530	90,754	5,691	0	374,085	21,652	0
47	Winter Billing kW		2,308,140	0	1,428,629	0	########	20,546	842,813	157,427	11,037	0	674,349	36,698	0
48	Tot Summer Reqt	$ / kW	$0.00	$0.00	$18.99	$0.00	$15.97	$15.57	$14.99	$19.72	$18.11	$0.00	$13.81	$10.43	$0.00
49	Tot Winter Reqt	$ / kW	$0.00	$0.00	$10.56	$0.00	$8.91	$8.55	$8.62	$11.71	$10.27	$0.00	$7.86	$6.14	$0.00
50	Energy + Production (Genco)		125,967	43,702	50,018	8,278	41,086	655	30,841	6,669	442	0	23,730	724	681

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
Compliance Class Cost of Service Study

(Comm / Indus By Size)

Case No. PU-07-____
Exhibit No. ______(PJZ-1)
Schedule 4

PROP vs Equal Rev Reqts

	Total Retail Rev Reqt	Alloc	ND	Res Tot	Sm Tot	Sm Non-D	Second	Primary	Lg Tot	Second	Primary	Trans	Interrupt	Muni Tot	Ltg Tot
			1=2+6+9+10	2=3 to 5	12=13 to 15	13	14	15	16=17 to 20	17	18	19	20	31=32+33	34=35 to 37
				0	0				0					0	0
1	Proposed Ret On Rt Base		9.20%	9.42%	9.66%	9.57%	9.69%	8.82%	7.51%	7.70%	10.18%	0.00%	7.39%	13.58%	10.60%
2	Equalized Rev Reqt		167,636	65,610	63,998	11,808	51,399	791	35,260	8,045	514	0	26,701	944	1,824
3	Proposed Revenue		167,636	65,968	64,712	11,915	52,012	784	34,025	7,766	525	0	25,734	1,050	1,880
4	Revenue Deficiency		0	(358)	(714)	(108)	(613)	7	1,235	279	(11)	0	967	(106)	(56)
5	Deficiency / Proposed		0.00%	-0.54%	-1.10%	-0.90%	-1.18%	0.90%	3.63%	3.59%	-2.09%	0.00%	3.76%	-10.13%	-2.98%
6	Firmed Up Revenue		3,784	417	78	19	59	0	3,289	0	0	0	3,289	0	0
7	Interruptible Capacity Costs	D10C	3,784	1,242	1,657	277	1,359	21	850	199	12	0	639	25	10
8	Revenue Shift		0	824	1,579	259	1,300	21	(2,439)	199	12	0	(2,650)	25	10
9	Adj Equal Rev (Rows 2+7)		171,420	66,852	65,655	12,085	52,758	812	36,110	8,244	527	0	27,340	969	1,834
10	Adj Prop Rev (Rows 3+6)		171,420	66,386	64,790	11,934	52,071	784	37,314	7,766	525	0	29,023	1,050	1,880
11	Adj Revenue Deficiency		0	466	866	151	687	28	(1,204)	478	1	0	(1,683)	(81)	(46)
12	Adj Deficiency / Adj Prop		0.00%	0.70%	1.34%	1.27%	1.32%	3.56%	-3.23%	6.15%	0.24%	0.00%	-5.80%	-7.73%	-2.46%
	Customer Component														
13	Min Sys & Service Drop		11,707	6,994	2,965	1,029	1,905	32	862	198	16	0	647	62	824
14	Energy Services		5,437	4,297	1,074	741	332	2	43	(2)	(0)	0	45	(0)	23
15	Total Customer **(Cusco)**		17,144	11,291	4,039	1,769	2,236	34	905	196	16	0	692	62	847
16	Ave Monthly Customers		87,633	73,609	11,652	8,553	3,080	18	190	4	1	0	185	182	2,000
17	Svc Drop Reqt	$ / Mo / Cust	$11.13	$7.92	$21.20	$10.02	$51.53	$143.84	$377.46	########	########	$0.00	$291.10	$28.49	$34.34
18	Ener Svcs Reqt	$ / Mo / Cust	$5.17	$4.87	$7.68	$7.22	$8.98	$8.17	$18.77	($44.25)	($4.26)	$0.00	$20.26	($0.08)	$0.95
19	Total Reqt	$ / Mo / Cust	$16.30	$12.78	$28.89	$17.24	$60.50	$152.02	$396.24	########	########	$0.00	$311.36	$28.42	$35.28
	Energy Component														
20	On Peak Rev Reqt		45,032	14,268	19,008	3,235	15,528	245	11,370	2,452	157	0	8,761	275	111
21	Off Peak Rev Reqt		38,232	14,944	13,383	2,113	11,087	183	9,330	1,958	140	0	7,232	189	386
22	Total Ener Rev Reqt		83,264	29,212	32,391	5,348	26,615	428	20,700	4,410	297	0	15,993	464	497
23	Annual Mwh Sales		2,217,924	782,202	836,541	134,951	690,197	11,393	568,703	119,144	8,335	0	441,224	11,761	18,717
24	On Pk Reqt	Mills / kWh	20.304	18.241	22.722	23.970	22.498	21.479	19.994	20.580	18.847	0.000	19.857	23.362	5.925
25	Off Pk Reqt	Mills / kWh	17.238	19.105	15.998	15.658	16.063	16.057	16.406	16.436	16.784	0.000	16.390	16.079	20.646
26	Total Reqt	Mills / kWh	37.541	37.346	38.720	39.629	38.562	37.536	36.399	37.016	35.631	0.000	36.247	39.441	26.570
	Demand Component														
27	Base Load Prod		21,888	8,477	8,739	1,529	7,105	104	4,316	1,001	73	0	3,242	161	195
28	Summer Peak Prod		15,564	5,386	6,860	1,175	5,602	82	3,130	768	51	0	2,311	121	67
29	Winter Peak Prod		5,250	2,155	2,032	364	1,643	24	971	224	15	0	731	36	57
30	Total Production		42,702	16,018	17,631	3,069	14,351	211	8,417	1,993	139	0	6,285	318	319
31	Transmission **(Transco)**		14,230	5,714	6,283	1,091	5,118	74	1,997	683	47	0	1,266	118	118
32	Primary Dist Subs		2,834	1,166	1,114	192	909	13	502	121	9	0	372	21	31
33	Prim Dist Lines		3,246	1,116	1,389	214	1,158	17	683	160	11	0	512	25	33
34	Second Dist, Trans		4,215	1,451	1,867	232	1,625	9	822	202	6	0	613	42	34
35	Total Distribution **(Disco)**		10,296	3,734	4,369	638	3,692	39	2,006	483	26	0	1,497	88	99
36	Total Demand Rev Reqt		67,228	25,465	28,282	4,798	23,161	323	12,420	3,159	212	0	9,048	524	536
37	Annual Billing kW		3,530,304	0	2,158,612	0	########	31,468	########	248,181	16,727	0	########	58,350	0
38	Base Rev Reqt	$ / kW	$0.00	$0.00	$4.05	$0.00	$3.34	$3.31	$3.29	$4.03	$4.35	$0.00	$3.09	$2.76	$0.00
39	Summer Rev Reqt	$ / kW	$0.00	$0.00	$3.18	$0.00	$2.63	$2.61	$2.38	$3.10	$3.04	$0.00	$2.20	$2.08	$0.00
40	Winter Rev Reqt	$ / kW	$0.00	$0.00	$0.94	$0.00	$0.77	$0.77	$0.74	$0.90	$0.93	$0.00	$0.70	$0.61	$0.00
41	Prod Rev Reqt	$ / kW	$0.00	$0.00	$8.17	$0.00	$6.75	$6.69	$6.41	$8.03	$8.32	$0.00	$5.99	$5.45	$0.00
42	Tran Rev Reqt	$ / kW	$0.00	$0.00	$2.91	$0.00	$2.41	$2.35	$1.52	$2.75	$2.84	$0.00	$1.21	$2.02	$0.00
43	Dist Rev Reqt	$ / kW	$0.00	$0.00	$2.02	$0.00	$1.74	$1.23	$1.53	$1.95	$1.53	$0.00	$1.43	$1.51	$0.00
44	Tot Dmd Rev Reqt		$0.00	$0.00	$13.10	$0.00	$10.89	$10.27	$9.46	$12.73	$12.68	$0.00	$8.63	$8.99	$0.00
45	Tot Dmd Rev Reqt	Mills / kWh	30.311	32.556	33.809	35.556	33.557	28.374	21.839	26.517	25.457	0.000	20.507	44.580	28.638
46	Summer Billing kW		1,222,164	0	729,982	0	719,060	10,922	470,530	90,754	5,691	0	374,085	21,652	0
47	Winter Billing kW		2,308,140	0	1,428,629	0	########	20,546	842,813	157,427	11,037	0	674,349	36,698	0
48	Tot Summer Reqt	$ / kW	$0.00	$0.00	$18.38	$0.00	$15.27	$14.41	$12.99	$17.20	$17.65	$0.00	$11.91	$11.89	$0.00
49	Tot Winter Reqt	$ / kW	$0.00	$0.00	$10.41	$0.00	$8.65	$8.07	$7.49	$10.15	$10.12	$0.00	$6.81	$7.27	$0.00
50	Energy + Production **(Genco)**		125,967	45,229	50,021	8,417	40,966	638	29,117	6,403	436	0	22,278	782	816
51	Prop Rev - Pres Rev (Pg 2)		20,457	8,245	7,769	1,541	6,145	83	4,272	917	60	0	3,294	172	(0)
52	Difference / Present		13.90%	14.28%	13.64%	14.85%	13.40%	11.76%	14.36%	13.40%	13.00%	#DIV/0!	14.68%	19.60%	-0.02%
53	Adj Prop - Adj Pres (Pg 2)		20,457	8,245	7,769	1,541	6,145	83	4,272	917	60	0	3,294	172	(0)
54	Difference / Adj Present		13.55%	14.18%	13.62%	14.82%	13.38%	11.76%	12.93%	13.40%	13.00%	#DIV/0!	12.80%	19.60%	-0.02%

Original Plant in Service

		Alloc	1=2+6+9+10	2=3 to 5	12=13 to 15	13	14	15	16=17 to 20	17	18	19	20	31=32+33	34=35 to 37
				0	0				0					0	0
	Production	Alloc	ND	Res Tot	Sm Tot	Sm Non-D	Second	Primary	Lg Tot	Second	Primary	Trans	Interrupt	Muni Tot	Ltg Tot
1	Summer Peak	D10S	68,310	20,654	31,384	5,175	25,815	394	15,790	3,778	229	0	11,782	482	0
2	Winter Peak	D10W	23,044	9,323	8,621	1,522	6,990	109	4,734	1,028	66	0	3,639	127	239
3	Total Peak	[D10C]	91,354	29,977	40,005	6,697	32,805	503	20,523	4,807	295	0	15,421	610	239
4	Base Load	D8760	180,880	63,500	70,346	11,612	57,805	929	44,953	9,574	645	0	34,734	1,005	1,077
5	Nuclear Fuel	D8760	84,470	29,654	32,851	5,423	26,995	434	20,993	4,471	301	0	16,220	469	503
6	Total	33.56%	356,704	123,131	143,201	23,732	117,604	1,866	86,469	18,852	1,241	0	66,376	2,083	1,819
	Transmission														
7	Gen Step Up Base	D8760	1,067	375	415	68	341	5	265	56	4	0	205	6	6
8	Gen Step Up Peak	D10C	1,416	465	620	104	508	8	318	75	5	0	239	9	4
9	Total Gen Step Up		2,483	839	1,035	172	849	13	583	131	8	0	444	15	10
10	Bulk Transmission	D10T	85,060	32,231	40,865	6,685	33,659	521	10,962	4,973	307	0	5,681	629	373
11	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Direct Assign	Dir Assign	14	0	0	0	0	0	14	0	0	0	14	0	0
13	Total		87,557	33,070	41,900	6,857	34,509	534	11,559	5,104	316	0	6,139	644	383
	Distribution:														
	Substations														
14	Generat Step Up	STRATH	291	101	117	19	96	2	71	15	1	0	54	2	1
15	Bulk Transmission	D10T	130	49	62	10	51	1	17	8	0	0	9	1	1
16	Distrib Function	D60Sub	17,218	6,934	6,493	1,036	5,375	81	3,508	791	50	0	2,666	104	180
17	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Total		17,639	7,084	6,672	1,065	5,523	84	3,595	814	52	0	2,729	107	182
	Overhead Lines														
19	Primary Capacity	D61PS	9,712	2,934	4,257	591	3,611	55	2,361	533	34	0	1,795	69	91
20	Primary Customer	C61PS	6,058	5,198	827	607	219	1	14	0	0	0	13	13	6
21	Total Primary		15,770	8,132	5,084	1,198	3,830	56	2,375	533	34	0	1,808	82	97
22	Second Capacity	D62SecL	3,831	1,037	1,826	147	1,679	0	907	217	0	0	690	41	20
23	Second Customer	C62Sec	3,812	3,272	520	382	138	0	8	0	0	0	8	8	4
24	Total Secondary		7,643	4,309	2,346	529	1,817	0	915	217	0	0	698	49	24
25	Street Lighting	DASL	1,643	0	0	0	0	0	0	0	0	0	0	0	1,643
26	Total		25,056	12,441	7,430	1,727	5,647	56	3,290	750	34	0	2,506	130	1,764
	Underground Lines														
27	Primary Capacity	D61PS	4,120	1,245	1,806	251	1,532	23	1,002	226	14	0	761	29	39
28	Primary Customer	C61PS	19,809	16,997	2,705	1,985	715	4	44	1	0	0	43	42	21
29	Total Primary		23,929	18,242	4,511	2,236	2,247	27	1,046	227	15	0	804	71	59
30	Second Capacity	D62SecL	9,811	2,656	4,677	377	4,300	0	2,323	555	0	0	1,768	104	51
31	Second Customer	C62Sec	10,770	9,245	1,469	1,080	389	0	23	1	0	0	22	23	11
32	Total Secondary		20,581	11,901	6,146	1,456	4,689	0	2,345	555	0	0	1,790	127	62
33	Total		44,510	30,143	10,656	3,693	6,936	27	3,391	782	15	0	2,594	198	121
	Line Transformers														
34	Primary	D61PS	874	264	383	53	325	5	212	48	3	0	162	6	8
35	Second Capacity	D62SecL	9,048	2,450	4,313	347	3,966	0	2,142	512	0	0	1,630	96	47
36	Second Customer	C62Sec	6,392	5,487	872	641	231	0	13	0	0	0	13	14	7
37	Total		16,314	8,201	5,568	1,041	4,522	5	2,368	560	3	0	1,805	116	62
	Services														
38	Second Capacity	D62NLL	3,172	1,124	1,335	48	1,287	0	678	150	0	0	527	36	0
39	Second Customer	C62NL	8,435	7,978	444	326	117	0	7	0	0	0	7	7	0
40	Total		11,607	9,102	1,778	374	1,405	0	684	150	0	0	534	43	0
41	Meters	C12WM	7,322	4,379	2,040	1,442	519	79	845	1	4	0	839	54	4
42	Street Lighting	Dir Assign	1,754	0	0	0	0	0	0	0	0	0	0	0	1,754
43	**Total Distribution**		124,202	71,349	34,145	9,343	24,552	251	14,172	3,058	107	0	11,007	647	3,888
44	**General Plant**	PTD	14,538	5,819	5,607	1,021	4,518	68	2,869	691	43	0	2,136	86	156
45	**Electric Common**	PTD	24,338	9,742	9,387	1,710	7,564	113	4,804	1,157	71	0	3,576	144	261
46	Prelim Elec Plant		607,339	243,112	234,240	42,662	188,746	2,832	119,874	28,862	1,778	0	89,234	3,606	6,507
47	TBT Investment	NEPIS	0	0	0	0	0	0	0	0	0	0	0	0	0
48	**Elec Plant in Serv**		607,339	243,112	234,240	42,662	188,746	2,832	119,874	28,862	1,778	0	89,234	3,606	6,507

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
Compliance Class Cost of Service Study

(Comm / Indus By Size)

Case No. PU-07-____
Exhibit No. ______(PJZ-1)
Schedule 4
Page 6 of 19

Accum Deprec; Net Plant

		Alloc	1=2+6+9+10 ND	2=3 to 5 0 Res Tot	12=13 to 15 0 Sm Tot	13 Sm Non-D	14 Second	15 Primary	16=17 to 20 0 Lg Tot	17 Second	18 Primary	19 Trans	20 Interrupt	31=32+33 0 Muni Tot	34=35 to 37 0 Ltg Tot
	Production														
1	Peaking Plant	D10C	40,494	13,288	17,733	2,969	14,541	223	9,097	2,131	131	0	6,836	270	106
2	Nuclear Fuel	D8760	76,688	26,922	29,825	4,923	24,508	394	19,059	4,059	273	0	14,726	426	457
3	Base Load	D8760	117,157	41,129	45,564	7,521	37,441	602	29,116	6,201	417	0	22,497	651	697
4	Total		234,339	81,339	93,121	15,413	76,490	1,218	57,272	12,391	822	0	44,059	1,347	1,260
	Transmission														
5	Gen Step Up Base	D8760	609	214	237	39	195	3	151	32	2	0	117	3	4
6	Gen Step Up Peak	D10C	808	265	354	59	290	4	182	43	3	0	136	5	2
7	Total Gen Step Up		1,417	479	591	98	485	8	333	75	5	0	253	9	6
8	Bulk Transmission	D10T	28,520	10,807	13,702	2,241	11,286	175	3,675	1,667	103	0	1,905	211	125
9	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	4	0	0	0	0	0	4	0	0	0	4	0	0
11	Total		29,941	11,286	14,292	2,340	11,770	182	4,012	1,742	108	0	2,162	220	131
	Distribution														
12	Generat Step Up	STRATH	108	37	43	7	36	1	26	6	0	0	20	1	1
13	Bulk Transmission	D10T	50	19	24	4	20	0	6	3	0	0	3	0	0
14	Distrib Function	D60Sub	6,380	2,569	2,406	384	1,992	30	1,300	293	19	0	988	38	67
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Total Substations		6,538	2,626	2,473	395	2,047	31	1,332	302	19	0	1,011	39	68
17	Overhead Lines	POL	9,529	4,731	2,826	657	2,147	21	1,251	285	13	0	953	50	671
18	Underground	PUL	16,898	11,444	4,046	1,402	2,633	10	1,287	297	6	0	985	75	46
19	Line Transformers	P68	6,400	3,217	2,184	409	1,774	2	929	220	1	0	708	45	24
20	Services	P69	4,553	3,570	698	147	551	0	268	59	0	0	210	17	0
21	Meters	C12WM	2,872	1,718	800	566	204	31	331	1	2	0	329	21	2
22	Street Lighting	P73	1,449	0	0	0	0	0	0	0	0	0	0	0	1,449
23	Total		48,239	27,305	13,027	3,575	9,357	96	5,399	1,163	40	0	4,196	248	2,259
24	**General Plant**	PTD	6,955	2,784	2,682	489	2,161	32	1,373	331	20	0	1,022	41	75
25	**Electric Common**	PTD	13,692	5,481	5,281	962	4,255	64	2,702	651	40	0	2,012	81	147
26	**Total Accum Depr**		333,166	128,195	128,403	22,777	104,033	1,592	70,759	16,278	1,030	0	53,451	1,937	3,872
27	**Net Elec Plant**		274,173	114,917	105,837	19,885	84,713	1,239	49,115	12,584	747	0	35,783	1,669	2,635

Subtractions: Accum Defer Inc Tax

		Alloc	ND	Res Tot	Sm Tot	Sm Non-D	Second	Primary	Lg Tot	Second	Primary	Trans	Interrupt	Muni Tot	Ltg Tot
	Production														
28	Peaking Plant	D10C	5,814	1,908	2,546	426	2,088	32	1,306	306	19	0	982	39	15
29	Base Load	D8760	8,873	3,115	3,451	570	2,836	46	2,205	470	32	0	1,704	49	53
30	Nuclear Fuel	D8760	(67)	(24)	(26)	(4)	(21)	(0)	(17)	(4)	(0)	0	(13)	(0)	(0)
31	Total		14,620	4,999	5,971	992	4,902	77	3,495	772	50	0	2,672	88	68
	Transmission														
32	Gen Step Up Base	D8760	129	45	50	8	41	1	32	7	0	0	25	1	1
33	Gen Step Up Peak	D10C	172	56	75	13	62	1	39	9	1	0	29	1	0
34	Total Gen Step Up		301	102	125	21	103	2	71	16	1	0	54	2	1
35	Bulk Transmission	D10T	8,996	3,409	4,322	707	3,560	55	1,159	526	33	0	601	66	39
36	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Direct Assign	Dir Assign	1	0	0	0	0	0	1	0	0	0	1	0	0
38	Total		9,298	3,510	4,447	728	3,663	57	1,231	542	34	0	656	68	41
	Distribution														
39	Generat Step Up	STRATH	48	17	19	3	16	0	12	3	0	0	9	0	0
40	Bulk Transmission	D10T	23	9	11	2	9	0	3	1	0	0	2	0	0
41	Distrib Function	D60Sub	2,100	846	792	126	656	10	428	97	6	0	325	13	22
42	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0
43	Total Substations		2,171	871	822	131	681	10	442	100	6	0	336	13	22
44	Overhead Lines	POL	3,367	1,672	998	232	759	8	442	101	5	0	337	18	237
45	Underground	PUL	5,551	3,759	1,329	460	865	3	423	98	2	0	323	25	15
46	Line Transformers	P68	2,464	1,239	841	157	683	1	358	85	0	0	273	17	9
47	Services	P69	1,679	1,317	257	54	203	0	99	22	0	0	77	6	0
48	Meters	C12WM	807	483	225	159	57	9	93	0	0	0	92	6	0
49	Street Lighting	P73	(184)	0	0	0	0	0	0	0	0	0	0	0	(184)
50	Total		15,855	9,340	4,473	1,194	3,248	31	1,857	405	14	0	1,438	85	100
51	**General Plant**	PTD	1,370	548	528	96	426	6	270	65	4	0	201	8	15
52	**Electric Common**	PTD	1,937	775	747	136	602	9	382	92	6	0	285	11	21
53	**Total Deferred Tax**		43,080	19,173	16,166	3,146	12,840	180	7,235	1,876	107	0	5,252	261	244
54	TBT Acc Def Tax	NEPIS	0	0	0	0	0	0	0	0	0	0	0	0	0
55	Non-Plant Related	LABOR	(2,363)	(1,023)	(859)	(184)	(665)	(10)	(434)	(100)	(6)	0	(328)	(12)	(35)
56	**Accum Def W/(Adj**		40,717	18,150	15,307	2,962	12,175	170	6,802	1,777	101	0	4,924	248	209

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
Compliance Class Cost of Service Study

(Comm / Indus By Size)

Case No. PU-07-____
Exhibit No. ______(PJZ-1)
Schedule 4
Page 7 of 19

Additions: CWIP, Etc; Rate Base

			1=2+6+9+10	2=3 to 5	12=13 to 15	13	14	15	16=17 to 20	17	18	19	20	31=32+33	34=35 to 37
				0	0				0					0	0
	CWIP														
	Production	**Alloc**	**ND**	**Res Tot**	**Sm Tot**	**Sm Non-D**	**Second**	**Primary**	**Lg Tot**	**Second**	**Primary**	**Trans**	**Interrupt**	**Muni Tot**	**Ltg Tot**
1	Peaking Plant	D10C	2,263	742	991	166	812	12	508	119	7	0	382	15	6
2	Base Load	D8760	1,182	415	460	76	378	6	294	63	4	0	227	7	7
3	Nuclear Fuel	D8760	699	246	272	45	224	4	174	37	2	0	134	4	4
4	Total		4,144	1,403	1,723	287	1,414	22	976	219	14	0	743	26	17
	Transmission														
5	Gen Step Up Base	D8760	1	0	1	0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10C	2	1	1	0	1	0	0	0	0	0	0	0	0
7	Total Gen Step Up		3	1	1	0	1	0	1	0	0	0	1	0	0
8	Bulk Transmission	D10T	521	197	250	41	206	3	67	30	2	0	35	4	2
9	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Total		524	198	251	41	207	3	68	31	2	0	35	4	2
	Distribution														
12	Generat Step Up	STRATH	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub	1	0	0	0	0	0	0	0	0	0	0	0	0
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Total Substations		1	0	0	0	0	0	0	0	0	0	0	0	0
17	Overhead Lines	POL	9	5	3	1	2	0	1	0	0	0	1	0	1
18	Underground	PUL	16	11	4	1	3	0	1	0	0	0	1	0	0
19	Line Transformers	P68	6	3	2	0	2	0	1	0	0	0	1	0	0
20	Services	P69	4	4	1	0	1	0	0	0	0	0	0	0	0
21	Meters	C12WM	3	2	1	1	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73	1	0	0	0	0	0	0	0	0	0	0	0	1
23	Total		40	24	11	3	7	0	4	1	0	0	3	0	1
24	**General Plant**	PTD	53	21	20	4	16	0	10	2	0	0	8	0	1
25	**Electric Common**	PTD	41	16	16	3	13	0	8	2	0	0	6	0	0
26	**Total CWIP**		4,802	1,663	2,021	338	1,657	26	1,066	255	16	0	796	30	22
27	Fuel Inventory	E8760	2,358	828	917	151	754	12	586	125	8	0	453	13	14
	Materials & Supplies														
28	Production	P10	4,283	1,478	1,719	285	1,412	22	1,038	226	15	0	797	25	22
29	Trans & Distr	TD	1,129	557	405	86	315	4	137	44	2	0	91	7	23
30	Total		5,412	2,035	2,125	371	1,727	27	1,175	270	17	0	888	32	45
	Prepayments														
31	Miscellaneous	NEPIS	1,864	781	720	135	576	8	334	86	5	0	243	11	18
32	Total		1,864	781	720	135	576	8	334	86	5	0	243	11	18
33	Non-Plant Assets & Liab	LABOR	(6,928)	(2,999)	(2,519)	(539)	(1,950)	(30)	(1,272)	(292)	(18)	0	(962)	(36)	(102)
34	Working Cash	PT0	1,136	489	421	82	334	5	203	49	3	0	151	7	16
35	**Total Additions**		8,644	2,798	3,684	539	3,097	48	2,092	492	31	0	1,569	57	13
36	**Total Rate Base**		242,100	99,564	94,214	17,462	75,635	1,117	44,405	11,300	678	0	32,427	1,478	2,439
37	**Common Rate Base (@ 51.77%)**		125,335	51,544	48,775	9,040	39,156	578	22,989	5,850	351	0	16,788	765	1,262

Operating Rev (Cal Month)

			1=2+6+9+10	2=3 to 5	12=13 to 15	13	14	15	16=17 to 20	17	18	19	20	31=32+33	34=35 to 37
				0	0				0					0	0
	Retail Revenue	**Alloc**	**ND**	**Res Tot**	**Sm Tot**	**Sm Non-D**	**Second**	**Primary**	**Lg Tot**	**Second**	**Primary**	**Trans**	**Interrupt**	**Muni Tot**	**Ltg Tot**
1	Present Rate Revenue	R01; (calc)	147,179	57,724	56,944	10,375	45,867	702	29,753	6,848	465	0	22,440	878	1,881
2	Proposed Rate Revenue	PROREV; (calc)	167,636	65,968	64,712	11,915	52,012	784	34,025	7,766	525	0	25,734	1,050	1,880
	Other Retail Revenue														
3	Interdepartmental	R01; R02	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Gross Earnings Tax	R01; R02	0	0	0	0	0	0	0	0	0	0	0	0	0
6	CIP Adjustment to Program Costs	D62E38	0	0	0	0	0	0	0	0	0	0	0	0	0
7	**Tot Other Retail Rev**		0	0	0	0	0	0	0	0	0	0	0	0	0
	Other Operating Revenue														
8	Interchg Prod Capacity	P10	8,994	3,105	3,611	598	2,965	47	2,180	475	31	0	1,674	53	46
9	Interchg Prod Energy	E8760	11,623	4,080	4,520	746	3,714	60	2,889	615	41	0	2,232	65	69
10	Interchg Tr Bulk Supply	D10T	2,031	770	976	160	804	12	262	119	7	0	136	15	9
11	Dist Int Sales; Oth Serv	E8760	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Dist Overhd Line Rent	POL	251	125	74	17	57	1	33	8	0	0	25	1	18
13	Connection Charges	C11	173	145	23	17	6	0	0	0	0	0	0	0	4
14	Sales For Resale	E8760	12,380	4,346	4,815	795	3,956	64	3,077	655	44	0	2,377	69	74
15	Joint Op Agree-Other PSCo Rev	D10T	(116)	(44)	(56)	(9)	(46)	(1)	(15)	(7)	(0)	0	(8)	(1)	(1)
16	Production Assoc'd Rev	E8760	375	132	146	24	120	2	93	20	1	0	72	2	2
17	Misc Ancillary Trans Rev	D10T	3,008	1,140	1,445	236	1,190	18	388	176	11	0	201	22	13
18	MISO	D10T	241	91	116	19	95	1	31	14	1	0	16	2	1
19	Other	D10T	320	121	154	25	127	2	41	19	1	0	21	2	1
20	Late Pay Chg - Pres	R16C; R02	245	146	82	15	66	1	16	4	0	0	12	0	0
21	**Tot Other Op - Pres**		39,525	14,157	15,906	2,644	13,055	207	8,995	2,098	139	0	6,759	230	237
22	Windsource Revenues	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Incr Misc Serv - Prop	R01,	44	17	17	3	14	0	9	2	0	0	7	0	1
24	Incr Late Pay - Prop	(R16C); R02	34	20	11	2	9	0	2	1	0	0	2	0	0
25	**Tot Other Op - Prop**		39,603	14,194	15,934	2,649	13,078	208	9,006	2,100	139	0	6,767	230	237
26	**Tot Oper Rev - Pres**		186,704	71,880	72,850	13,018	58,922	909	38,749	8,946	604	0	29,199	1,108	2,117
27	**Tot Oper Rev - Prop**		207,239	80,162	80,647	14,564	65,090	992	43,031	9,866	664	0	32,501	1,281	2,117

Operating & Maint (Pg 1 of 2)

			ND	Res Tot	Sm Tot	Sm Non-D	Second	Primary	Lg Tot	Second	Primary	Trans	Interrupt	Muni Tot	Ltg Tot
	Production Expen														
28	**Fuel**	E8760	35,469	12,452	13,794	2,277	11,335	182	8,815	1,877	126	0	6,811	197	211
	Purchased Power														
29	Purchases: Cap Peak	D10C	5,554	1,822	2,432	407	1,994	31	1,248	292	18	0	938	37	15
30	Purchases: Cap Base	D8760	4,183	1,468	1,627	268	1,337	21	1,039	221	15	0	803	23	25
31	Purchases: Demand		9,737	3,291	4,059	676	3,331	52	2,287	514	33	0	1,741	60	39
32	Purchases: Other Energy	E8760	43,614	15,311	16,962	2,800	13,938	224	10,839	2,309	155	0	8,375	242	260
33	Tot Non-Assoc Purch		53,351	18,602	21,021	3,475	17,269	276	13,126	2,822	188	0	10,116	303	299
34	Interchg Agr Capacity	P10	2,290	790	919	152	755	12	555	121	8	0	426	13	12
35	Interchg Agr Energy	E8760	1,340	470	521	86	428	7	333	71	5	0	257	7	8
36	Tot Wis Interchg Purch		3,630	1,261	1,441	238	1,183	19	888	192	13	0	683	21	20
37	**Tot Purchased Power**		56,981	19,863	22,461	3,714	18,452	295	14,014	3,014	201	0	10,799	323	319
	Other Production														
38	Capacity Peaking	D10C	3,953	1,297	1,731	290	1,420	22	888	208	13	0	667	26	10
39	Capacity Baseload	D8760	2,977	1,045	1,158	191	951	15	740	158	11	0	572	17	18
40	Total Capacity		6,930	2,342	2,889	481	2,371	37	1,628	366	23	0	1,239	43	28
41	Energy	E8760	20,127	7,066	7,828	1,292	6,432	103	5,002	1,065	72	0	3,865	112	120
42	Total Other Produc		27,057	9,408	10,716	1,773	8,803	140	6,630	1,431	95	0	5,104	155	148
43	**Total Production**		119,506	41,723	46,971	7,764	38,590	618	29,459	6,323	423	0	22,714	675	678
44	**Transmission Exp**	D10T	7,992	3,028	3,839	628	3,162	49	1,030	467	29	0	534	59	35

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
Compliance Class Cost of Service Study

(Comm / Indus By Size)

Case No. PU-07-____
Exhibit No. ______(PJZ-1)
Schedule 4
Page 9 of 19

Operating & Maint (Pg 2 of 2)

			1=2+6+9+10	2=3 to 5	12=13 to 15	13	14	15	16=17 to 20	17	18	19	20	31=32+33	34=35 to 37
				0	0				0					0	0
	Distribution Expen	**Alloc**	**ND**	**Res Tot**	**Sm Tot**	**Sm Non-D**	**Second**	**Primary**	**Lg Tot**	**Second**	**Primary**	**Trans**	**Interrupt**	**Muni Tot**	**Ltg Tot**
1	Supervision & Eng'rg	ZDTS	423	229	122	34	87	1	48	11	1	0	36	2	22
2	Load Dispatching	D10T	247	94	119	19	98	2	32	14	1	0	17	2	1
3	Substations	P61	324	130	123	20	102	2	66	15	1	0	50	2	3
4	Overhead Lines	POL	2,065	1,026	613	142	465	5	271	62	3	0	207	11	145
5	Underground Lines	PUL	1,276	864	305	106	199	1	97	22	0	0	74	6	3
6	Line Transformers	P68	14	7	5	1	4	0	2	0	0	0	2	0	0
7	Meters	C12WM	179	107	50	35	13	2	21	0	0	0	20	1	0
8	Customer Install'n	OXDTS	42	21	12	3	8	0	5	1	0	0	4	0	4
9	Street Lighting	Dir Assign	219	0	0	0	0	0	0	0	0	0	0	0	219
10	Miscellaneous	OXDTS	731	376	206	55	149	2	83	19	1	0	63	4	63
11	Rents (Pole Attachmts)	POL	134	66	40	9	30	0	18	4	0	0	13	1	9
12	**Total Distribution**		5,655	2,920	1,593	425	1,155	14	642	150	7	0	486	28	471
13	**Customer Accounting**	C11WA	4,343	3,402	882	595	285	2	44	1	0	0	43	0	15
14	**Econ Development**	D100E0	2	1	1	0	1	0	0	0	0	0	0	0	0
	Admin & General														
15	Salaries	LABOR	2,885	1,249	1,049	224	812	12	530	122	8	0	401	15	42
16	Office Supplies	OXTS	2,784	1,045	1,075	192	869	14	624	139	9	0	476	15	25
17	Admin Transfer Credit	OXTS	(769)	(289)	(297)	(53)	(240)	(4)	(172)	(38)	(3)	0	(131)	(4)	(7)
18	Outside Services	LABOR	798	346	290	62	225	3	147	34	2	0	111	4	12
19	Property Insurance	NEPIS	315	132	121	23	97	1	56	14	1	0	41	2	3
20	Pensions & Benefits	LABOR	2,613	1,131	950	203	736	11	480	110	7	0	363	14	38
21	Injuries & Claims	LABOR	674	292	245	52	190	3	124	28	2	0	94	4	10
22	Regulatory Exp	R01; R02	70	28	27	5	22	0	14	3	0	0	11	0	1
23	General Advertising	OXTS	13	5	5	1	4	0	3	1	0	0	2	0	0
24	Contributions	OXTS	86	32	33	6	27	0	19	4	0	0	15	0	1
25	Misc General Exp	OXTS	234	88	90	16	73	1	52	12	1	0	40	1	2
26	Rents	OXTS	672	252	259	46	210	3	151	34	2	0	115	4	6
27	Maint of General Plant	OXTS	24	9	9	2	8	0	5	1	0	0	4	0	0
28	Total		10,399	4,319	3,858	780	3,032	46	2,033	464	30	0	1,540	56	134
	Cust Service & Info														
29	Cust Assist Exp - Non-CIP	C11P10	193	114	52	16	35	1	24	5	0	0	18	1	3
30	CIP Total	D62E38	38	14	17	3	14	0	7	2	0	0	4	0	0
31	Instructional Advertising	C11P10	138	82	37	11	25	0	17	4	0	0	13	1	2
32	Total		369	210	105	30	74	1	47	11	1	0	35	2	5
33	Amortizations	LABOR	460	199	167	36	130	2	84	19	1	0	64	2	7
34	**Total O&M Expense**		148,725	55,802	57,417	10,257	46,429	731	33,340	7,434	490	0	25,416	822	1,344

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
Compliance Class Cost of Service Study

(Comm / Indus By Size)

Case No. PU-07-____
Exhibit No. ______(PJZ-1)
Schedule 4

Book Depreciation

			1=2+6+9+10	2=3 to 5	12=13 to 15	13	14	15	16=17 to 20	17	18	19	20	31=32+33	34=35 to 37
				0	0				0					0	0
	Production	**Alloc**	**ND**	**Res Tot**	**Sm Tot**	**Sm Non-D**	**Second**	**Primary**	**Lg Tot**	**Second**	**Primary**	**Trans**	**Interrupt**	**Muni Tot**	**Ltg Tot**
1	Peaking Plant	D10C	3,212	1,054	1,407	235	1,153	18	722	169	10	0	542	21	8
2	Base Load	D8760	7,108	2,495	2,764	456	2,272	37	1,767	376	25	0	1,365	39	42
3	Total		10,320	3,549	4,171	692	3,425	54	2,488	545	36	0	1,907	61	51
	Transmission														
4	Gen Step Up Base	D8760	28	10	11	2	9	0	7	1	0	0	5	0	0
5	Gen Step Up Peak	D10C	37	12	16	3	13	0	8	2	0	0	6	0	0
6	Total Gen Step Up		65	22	27	5	22	0	15	3	0	0	12	0	0
7	Bulk Transmission	D10T	2,267	859	1,089	178	897	14	292	133	8	0	151	17	10
8	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Total		2,332	881	1,116	183	919	14	307	136	8	0	163	17	10
	Distribution														
11	Generat Step Up	STRATH	8	3	3	1	3	0	2	0	0	0	1	0	0
12	Bulk Transmission	D10T	4	2	2	0	2	0	1	0	0	0	0	0	0
13	Distrib Function	D60Sub	477	192	180	29	149	2	97	22	1	0	74	3	5
14	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Total Substations		489	196	185	30	153	2	100	23	1	0	76	3	5
16	Overhead Lines	POL	722	359	214	50	163	2	95	22	1	0	72	4	51
17	Underground	PUL	1,282	868	307	106	200	1	98	23	0	0	75	6	3
18	Line Transformers	P68	528	265	180	34	146	0	77	18	0	0	58	4	2
19	Services	P69	375	294	57	12	45	0	22	5	0	0	17	1	0
20	Meters	C12WM	237	142	66	47	17	3	27	0	0	0	27	2	0
21	Street Lighting	P73	117	0	0	0	0	0	0	0	0	0	0	0	117
22	Total		3,750	2,124	1,010	278	724	7	418	90	3	0	325	19	179
23	**General Plant**	PTD	749	300	289	53	233	3	148	36	2	0	110	4	8
24	**Electric Common**	PTD	2,009	804	775	141	624	9	397	95	6	0	295	12	22
25	**Total Book Deprec**		19,160	7,659	7,361	1,346	5,926	89	3,758	902	55	0	2,801	114	269
	Real Estate & Property Tax														
	Production														
26	Peaking Plant	D10C	632	207	277	46	227	3	142	33	2	0	107	4	2
27	Base Load	D8760	1,809	635	704	116	578	9	450	96	6	0	347	10	11
28	Total		2,441	842	980	162	805	13	592	129	8	0	454	14	12
	Transmission														
29	Gen Step Up Base	D8760	53	19	21	3	17	0	13	3	0	0	10	0	0
30	Gen Step Up Peak	D10C	186	61	81	14	67	1	42	10	1	0	31	1	0
31	Total Gen Step Up		239	80	102	17	84	1	55	13	1	0	42	2	1
32	Bulk Transmission	D10T	838	318	403	66	332	5	108	49	3	0	56	6	4
33	Distrib Function	D60Sub	1	0	0	0	0	0	0	0	0	0	0	0	0
34	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0
35	Total		1,078	398	505	83	416	6	163	62	4	0	98	8	4
	Distribution														
36	Generat Step Up	STRATH	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Bulk Transmission	D10T	36	14	17	3	14	0	5	2	0	0	2	0	0
38	Distrib Function	D60Sub	366	147	138	22	114	2	75	17	1	0	57	2	4
39	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0
40	Total Substations		402	161	155	25	129	2	79	19	1	0	59	2	4
41	Overhead Lines	POL	417	207	124	29	94	1	55	12	1	0	42	2	29
42	Underground	PUL	627	425	150	52	98	0	48	11	0	0	37	3	2
43	Line Transformers	P68	428	215	146	27	119	0	62	15	0	0	47	3	2
44	Services	P69	172	135	26	6	21	0	10	2	0	0	8	1	0
45	Meters	C12WM	168	100	47	33	12	2	19	0	0	0	19	1	0
46	Street Lighting	P73	30	0	0	0	0	0	0	0	0	0	0	0	30
47	Total		2,244	1,243	648	172	472	5	273	59	2	0	212	12	67
48	**General Plant**	PTD	0	0	0	0	0	0	0	0	0	0	0	0	0
49	**Electric Common**	PTD	0	0	0	0	0	0	0	0	0	0	0	0	0
50	**Tot Rl Est & Pr Tax**		5,763	2,483	2,134	417	1,692	24	1,028	250	14	0	764	34	84
51	Gross Earnings Tax	R01; R02	0	0	0	0	0	0	0	0	0	0	0	0	0
52	Payroll Taxes	LABOR	1,310	567	476	102	369	6	241	55	3	0	182	7	19
53	**Tot Non-Inc Taxes**		7,073	3,050	2,610	519	2,061	30	1,269	305	18	0	946	41	103

Provision For Defer Inc Tax

			1=2+8+9+10	2=3 to 5	12=13 to 15	13	14	15	16=17 to 20	17	18	19	20	31=32+33	34=35 to 37
				0	0				0					0	0
	Production	Alloc	ND	Res Tot	Sm Tot	Sm Non-D	Second	Primary	Lg Tot	Second	Primary	Trans	Interrupt	Muni Tot	Ltg Tot
1	Peaking Plant	D10C	1,214	398	531	89	436	7	273	64	4	0	205	8	3
2	Nuclear Fuel	D8760	78	27	30	5	25	0	19	4	0	0	15	0	0
3	Base Load	D8760	154	54	60	10	49	1	38	8	1	0	30	1	1
4	Total		1,446	480	622	104	510	8	330	76	5	0	249	9	5
	Transmission														
5	Gen Step Up Base	D8760	(6)	(2)	(2)	(0)	(2)	(0)	(1)	(0)	(0)	0	(1)	(0)	(0)
6	Gen Step Up Peak	D10C	(9)	(3)	(4)	(1)	(3)	(0)	(2)	(0)	(0)	0	(2)	(0)	(0)
7	Total Gen Step Up		(15)	(5)	(6)	(1)	(5)	(0)	(4)	(1)	(0)	0	(3)	(0)	(0)
8	Bulk Transmission	D10T	957	363	460	75	379	6	123	56	3	0	64	7	4
9	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Total		942	358	453	74	374	6	120	55	3	0	61	7	4
	Distribution														
12	Generat Step Up	STRATH	1	0	0	0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10T	7	3	3	1	3	0	1	0	0	0	0	0	0
14	Distrib Function	D60Sub	(13)	(5)	(5)	(1)	(4)	(0)	(3)	(1)	(0)	0	(2)	(0)	(0)
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Total Substations		(5)	(2)	(1)	(0)	(1)	(0)	(2)	(0)	(0)	0	(1)	(0)	(0)
17	Overhead Lines	POL	(24)	(12)	(7)	(2)	(5)	(0)	(3)	(1)	(0)	0	(2)	(0)	(2)
18	Underground	PUL	31	21	7	3	5	0	2	1	0	0	2	0	0
19	Line Transformers	P68	(122)	(61)	(42)	(8)	(34)	(0)	(18)	(4)	(0)	0	(13)	(1)	(0)
20	Services	P69	(56)	(44)	(9)	(2)	(7)	0	(3)	(1)	0	0	(3)	(0)	0
21	Meters	C12WM	11	7	3	2	1	0	1	0	0	0	1	0	0
22	Street Lighting	P73	(16)	0	0	0	0	0	0	0	0	0	0	0	(16)
23	Total		(181)	(92)	(48)	(7)	(41)	0	(22)	(5)	(0)	0	(17)	(1)	(18)
24	**General Plant**	PTD	76	30	29	5	24	0	15	4	0	0	11	0	1
25	**Electric Common**	PTD	(188)	(75)	(73)	(13)	(58)	(1)	(37)	(9)	(1)	0	(28)	(1)	(2)
26	**TBT Defer Inc Tax**	NEPIS	0	0	0	0	0	0	0	0	0	0	0	0	0
27	**Non - Plant Related**	LABOR	(93)	(40)	(34)	(7)	(26)	(0)	(17)	(4)	(0)	0	(13)	(0)	(1)
28	**Tot Prov For Defer**		2,002	660	950	156	781	13	389	117	8	0	265	14	(12)

Inv Tax Credit; Total Oper Exp

			ND	Res Tot	Sm Tot	Sm Non-D	Second	Primary	Lg Tot	Second	Primary	Trans	Interrupt	Muni Tot	Ltg Tot
	Production														
29	Peaking Plant	D10C	(38)	(12)	(17)	(3)	(14)	(0)	(9)	(2)	(0)	0	(6)	(0)	(0)
30	Base Load	D8760	(131)	(46)	(51)	(8)	(42)	(1)	(33)	(7)	(0)	0	(25)	(1)	(1)
31	Total		(169)	(58)	(68)	(11)	(56)	(1)	(41)	(9)	(1)	0	(32)	(1)	(1)
	Transmission														
32	Bulk Transmission	D10T	(36)	(14)	(17)	(3)	(14)	(0)	(5)	(2)	(0)	0	(2)	(0)	(0)
33	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Total		(36)	(14)	(17)	(3)	(14)	(0)	(5)	(2)	(0)	0	(2)	(0)	(0)
	Distribution														
35	Overhead Lines	POL	(18)	(9)	(5)	(1)	(4)	(0)	(2)	(1)	(0)	0	(2)	(0)	(1)
36	Underground	PUL	(40)	(27)	(10)	(3)	(6)	(0)	(3)	(1)	(0)	0	(2)	(0)	(0)
37	Total		(58)	(36)	(15)	(5)	(10)	(0)	(5)	(1)	(0)	0	(4)	(0)	(1)
38	**General Plant**	PTD	0	0	0	0	0	0	0	0	0	0	0	0	0
39	**Electric Common**	PTD	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0	(0)	(0)	(0)
40	**Net Inv Tax Credit**		(264)	(109)	(100)	(19)	(80)	(1)	(51)	(12)	(1)	0	(38)	(2)	(2)
41	**Total Operating Exp**		176,696	67,063	68,237	12,259	55,116	862	38,704	8,746	570	0	29,388	990	1,702
42A	**Pres Op Inc Before Inc Tax**		10,009	4,818	4,612	759	3,806	48	45	200	34	0	(189)	118	416
42B	**Prop Op Inc Before Inc Tax**		30,543	13,100	12,409	2,305	9,974	130	4,327	1,120	94	0	3,113	291	416

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
Compliance Class Cost of Service Study

(Comm / Indus By Size)

Case No. PU-07-____
Exhibit No. ______(PJZ-1)
Schedule 4
Page 12 of 19

Tax Deprec; Inc Tax & Return

		Alloc	1=2+6+9+10 ND	2=3 to 5 0 Res Tot	12=13 to 15 0 Sm Tot	13 Sm Non-D	14 Second	15 Primary	16=17 to 20 0 Lg Tot	17 Second	18 Primary	19 Trans	20 Interrupt	31=32+33 0 Muni Tot	34=35 to 37 0 Ltg Tot
	Production														
1	Peaking Plant	D10C	7,291	2,392	3,193	535	2,618	40	1,638	384	24	0	1,231	49	19
2	Nuclear Fuel	D8760	4,676	1,642	1,819	300	1,494	24	1,162	248	17	0	898	26	28
3	Base Load	D8760	7,795	2,737	3,032	500	2,491	40	1,937	413	28	0	1,497	43	46
4	Total		19,762	6,771	8,043	1,335	6,604	104	4,737	1,044	68	0	3,626	118	93
	Transmission														
5	Gen Step Up Base	D8760	12	4	5	1	4	0	3	1	0	0	2	0	0
6	Gen Step Up Peak	D10C	16	5	7	1	6	0	4	1	0	0	3	0	0
7	Total Gen Step Up		28	9	12	2	10	0	7	1	0	0	5	0	0
8	Bulk Transmission	D10T	4,777	1,810	2,295	375	1,890	29	616	279	17	0	319	35	21
9	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Total		4,805	1,820	2,307	377	1,900	29	622	281	17	0	324	35	21
	Distribution														
12	Generat Step Up	STRATH	10	3	4	1	3	0	2	1	0	0	2	0	0
13	Bulk Transmission	D10T	26	10	12	2	10	0	3	2	0	0	2	0	0
14	Distrib Function	D60Sub	446	180	168	27	139	2	91	20	1	0	69	3	5
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Total Substations		482	193	185	30	153	2	97	23	1	0	73	3	5
17	Overhead Lines	POL	614	305	182	42	138	1	81	18	1	0	61	3	43
18	Underground	PUL	1,408	954	337	117	219	1	107	25	0	0	82	6	4
19	Line Transformers	P68	262	132	89	17	73	0	38	9	0	0	29	2	1
20	Services	P69	367	288	56	12	44	0	22	5	0	0	17	1	0
21	Meters	C12WM	202	121	56	40	14	2	23	0	0	0	23	1	0
22	Street Lighting	P73	57	0	0	0	0	0	0	0	0	0	0	0	57
23	Total		3,392	1,992	906	257	642	7	367	79	3	0	285	17	110
24	**General Plant**	PTD	1,116	447	430	78	347	5	220	53	3	0	164	7	12
25	**Electric Common**	PTD	1,531	613	590	108	476	7	302	73	4	0	225	9	16
26	**TBT Defer Inc Tax**	NEPIS	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0	(0)	(0)	(0)
27	**Total Tax Deprec**		30,605	11,641	12,276	2,155	9,968	153	6,249	1,530	96	0	4,624	186	253
28	Interest Expense		7,868	3,236	3,062	568	2,458	36	1,443	367	22	0	1,054	48	79
29	Other Tax Timing Differ		64	24	31	5	25	0	8	4	0	0	4	0	0
30	Total Tax Deductions		38,537	14,901	15,369	2,728	12,451	189	7,701	1,901	118	0	5,682	235	332
	Inc Tax Additions														
31	Book Depreciation		19,160	7,659	7,361	1,346	5,926	89	3,758	902	55	0	2,801	114	269
32	Deferred Inc Tax & ITC		1,738	552	850	138	701	12	338	105	7	0	226	13	(14)
33	Nuclear Fuel Book Burn	E8760	4,012	1,408	1,560	258	1,282	21	997	212	14	0	770	22	24
34	Nuclear Fuel Disposal	D8760	721	253	280	46	230	4	179	38	3	0	138	4	4
35	Meals & Entertainment	LABOR	32	14	12	2	9	0	6	1	0	0	4	0	0
36	Avoided Tax Interest	RTBASE	3,412	1,403	1,328	246	1,066	16	626	159	10	0	457	21	34
37	Total Tax Additions		29,075	11,289	11,391	2,036	9,214	140	5,904	1,418	89	0	4,397	174	318
38	**Total Inc Tax Adjustments**		(9,462)	(3,612)	(3,978)	(692)	(3,237)	(49)	(1,797)	(483)	(30)	0	(1,284)	(61)	(15)
39A	**Pres Taxable Net Income**		546	1,206	635	67	569	(1)	(1,752)	(283)	4	0	(1,474)	57	401
39B	**Prop Taxable Net Income**		21,081	9,488	8,432	1,613	6,737	82	2,530	637	65	0	1,829	230	401
40A	Pres Fed & State Inc Tax		214	473	249	26	223	(1)	(687)	(111)	2	0	(578)	22	157
40B	Prop Fed & State Inc Tax		8,270	3,722	3,308	633	2,643	32	993	250	25	0	717	90	157
41A	Pres Preliminary Return	(total); BASE	9,794	4,345	4,363	732	3,583	48	732	311	32	0	389	96	258
41B	Prop Preliminary Return	(total); BASE	22,273	9,378	9,102	1,672	7,331	98	3,335	870	69	0	2,395	201	258
42	Total AFUDC		0	0	0	0	0	0	0	0	0	0	0	0	0
43A	**Present Total Return**		9,794	4,345	4,363	732	3,583	48	732	311	32	0	389	96	258
43B	**Proposed Total Return**		22,273	9,378	9,102	1,672	7,331	98	3,335	870	69	0	2,395	201	258
44A	**Pres % Return on Rate Base**		4.05%	4.36%	4.63%	4.19%	4.74%	4.31%	1.65%	2.75%	4.75%	0.00%	1.20%	6.49%	10.59%
44B	**Prop % Return on Rate Base**		9.20%	9.42%	9.66%	9.57%	9.69%	8.82%	7.51%	7.70%	10.18%	0.00%	7.39%	13.58%	10.60%
45A	**Present Common Return**		1,926	1,109	1,301	165	1,125	12	(711)	(56)	10	0	(665)	48	179
45B	**Proposed Common Return**		14,405	6,142	6,040	1,104	4,873	62	1,892	503	47	0	1,342	153	179
46A	**Pres % Ret on Common Rate Base**		1.54%	2.15%	2.67%	1.82%	2.87%	2.04%	-3.09%	-0.96%	2.90%	0.00%	-3.96%	6.25%	14.18%
46B	**Prop % Ret on Common Rate Base**		11.49%	11.92%	12.38%	12.22%	12.45%	10.75%	8.23%	8.60%	13.39%	0.00%	7.99%	19.94%	14.19%

Allow For Funds Used During Constr

		Alloc	ND	Res Tot	Sm Tot	Sm Non-D	Second	Primary	Lg Tot	Second	Primary	Trans	Interrupt	Muni Tot	Ltg Tot
			1=2+6+9+10	2=3 to 5	12=13 to 15	13	14	15	16=17 to 20	17	18	19	20	31=32+33	34=35 to 37
				0	0				0					0	0
	Production														
1	Peaking Plant	D10C	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Nuclear Fuel	D8760	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Base Load	D8760	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Total		0	0	0	0	0	0	0	0	0	0	0	0	0
	Transmission														
5	Gen Step Up Base	D8760	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Gen Step Up Peak	D10C	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Total Gen Step Up		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Total		0	0	0	0	0	0	0	0	0	0	0	0	0
	Distribution														
12	Generat Step Up	STRATH	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Bulk Transmission	D10T	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Distrib Function	D60Sub	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Direct Assign	Dir Assign	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Total Substations		0	0	0	0	0	0	0	0	0	0	0	0	0
17	Overhead Lines	POL	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Underground	PUL	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Line Transformers	P68	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Services	P69	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Meters	C12WM	0	0	0	0	0	0	0	0	0	0	0	0	0
22	Street Lighting	P73	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Total		0	0	0	0	0	0	0	0	0	0	0	0	0
24	**General Plant**	PTD	0	0	0	0	0	0	0	0	0	0	0	0	0
25	**Electric Common**	PTD	0	0	0	0	0	0	0	0	0	0	0	0	0
26	**Total AFUDC**		0	0	0	0	0	0	0	0	0	0	0	0	0

Labor Allocator

		Alloc	ND	Res Tot	Sm Tot	Sm Non-D	Second	Primary	Lg Tot	Second	Primary	Trans	Interrupt	Muni Tot	Ltg Tot
	Production														
27	Other Prod - Cap	OXOPD	4,376	1,479	1,824	304	1,497	23	1,028	231	15	0	782	27	18
28	Other Prod - Ene	E8760	3,296	1,157	1,282	212	1,053	17	819	174	12	0	633	18	20
29	Total		7,672	2,636	3,106	515	2,550	40	1,847	405	27	0	1,415	45	37
	Transmission														
30	Stepup Subtrans	P5161A	21	7	9	1	7	0	5	1	0	0	4	0	0
31	Bulk Power Subs	D10T	714	271	343	56	283	4	92	42	3	0	48	5	3
32	Total		735	278	352	58	290	4	97	43	3	0	51	5	3
	Distribution														
33	Superv & Eng	ZDTS	314	170	91	26	64	1	36	8	0	0	27	2	16
34	Load Dispatch	D10T	156	59	75	12	62	1	20	9	1	0	10	1	1
35	Substation	P61	199	80	75	12	62	1	41	9	1	0	31	1	2
36	Overhead Lines	POL	633	314	188	44	143	1	83	19	1	0	63	3	45
37	Underground Lines	PUL	750	508	180	62	117	0	57	13	0	0	44	3	2
38	Line Transformer	P68	1	0	0	0	0	0	0	0	0	0	0	0	0
39	Meter	C12WM	143	85	40	28	10	2	16	0	0	0	16	1	0
40	Cust Installation	ZDTS	26	14	8	2	5	0	3	1	0	0	2	0	1
41	Street Lighting	P73	41	0	0	0	0	0	0	0	0	0	0	0	41
42	Miscellaneous	OXDTS	312	161	88	23	64	1	35	8	0	0	27	2	27
43	Total		2,575	1,392	744	209	527	7	291	68	3	0	221	13	135
44	**Cust Accounting**	C11WA	1,201	941	244	164	79	0	12	0	0	0	12	0	4
45	**Sales Expense**	C11P10	2	1	0	0	0	0	0	0	0	0	0	0	0
46	**Admin & General**	LABOR	6,026	2,609	2,191	469	1,696	26	1,107	254	16	0	837	32	89
47	**Service & Inform**	C11P10	169	100	45	14	31	0	21	4	0	0	16	1	2
48	**Labor**		18,381	7,957	6,682	1,429	5,174	78	3,375	774	49	0	2,552	97	270

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
Compliance Class Cost of Service Study

(Comm / Indus By Size)

Case No. PU-07-____
Exhibit No. ______(PJZ-1)
Schedule 4
Page 14 of 19

Backwards Revenue Calc

		1=2+6+9+10	2=3 to 5	12=13 to 15	13	14	15	16=17 to 20	17	18	19	20	31=32+33	34=35 to 37
			0	0				0					0	0
	(1A) Modified Pres Rev	ND	Res Tot	Sm Tot	Sm Non-D	Second	Primary	Lg Tot	Second	Primary	Trans	Interrupt	Muni Tot	Ltg Tot
1	Present Preliminary Return (Before AFUDC)	9,794	4,345	4,363	732	3,583	48	732	311	32	0	389	96	258
2	1/(1-T) Rev Reqt (= 1.6455)	16,117	7,149	7,180	1,205	5,896	79	1,205	512	53	0	640	158	425
3	Total Inc Tax Adjustments	(9,462)	(3,612)	(3,978)	(692)	(3,237)	(49)	(1,797)	(483)	(30)	0	(1,284)	(61)	(15)
4	T/(1-T) Rev Reqt (= 0.6455)	(6,108)	(2,332)	(2,568)	(446)	(2,090)	(32)	(1,160)	(312)	(19)	0	(829)	(39)	(10)
5	Tot Op Exp W/o Regul Exp	176,625	67,035	68,210	12,254	55,094	861	38,690	8,743	569	0	29,378	989	1,701
6	- Other Retail Rev W/o Gr Earn, Etc	0	0	0	0	0	0	0	0	0	0	0	0	0
7	- Other Op Rev W/o Late Pay, Etc.	39,280	14,011	15,824	2,629	12,989	206	8,979	2,094	138	0	6,747	230	237
8	Modified Pres Net Oper Exp	137,345	53,024	52,387	9,626	42,106	655	29,711	6,649	431	0	22,631	759	1,464
9	Mod Pres Rev (R02) (component alloc)	147,354	57,842	56,999	10,385	45,912	703	29,756	6,849	465	0	22,442	878	1,880
	(1B) Present Revenue													
10	Tot Oper Exp (w/ Regul Exp)	176,696	67,063	68,237	12,259	55,116	862	38,704	8,746	570	0	29,388	990	1,702
11	- Other Retail Rev (w/ Gr Earn, Etc)	0	0	0	0	0	0	0	0	0	0	0	0	0
12	- Other Oper Rev (w/ Late Pay, Etc)	39,525	14,157	15,906	2,644	13,055	207	8,995	2,098	139	0	6,759	230	237
13	Net Oper Exp Rev Reqt	137,171	52,906	52,331	9,616	42,061	654	29,709	6,648	431	0	22,629	760	1,465
14	Tot Pres Rate Rev Reqt (R01)	147,179	57,724	56,944	10,375	45,867	702	29,753	6,848	465	0	22,440	878	1,881
	(2) Proposed Return													
15	Total Operating Exp	176,696	67,063	68,237	12,259	55,116	862	38,704	8,746	570	0	29,388	990	1,702
16	- Other Retail Rev (w/ Gr Earn, Etc)	0	0	0	0	0	0	0	0	0	0	0	0	0
17	- Prop Other Operating Rev	39,603	14,194	15,934	2,649	13,078	208	9,006	2,100	139	0	6,767	230	237
18	Prop Net Oper Exp Rev Reqt	137,093	52,868	52,303	9,611	42,038	654	29,698	6,646	431	0	22,621	759	1,464
19	Prop Preliminary Return	22,273	9,378	9,102	1,672	7,331	98	3,335	870	69	0	2,395	201	258
20	1/(1-T) Rev Reqt (= 1.6455)	36,651	15,431	14,977	2,751	12,064	162	5,488	1,432	114	0	3,942	330	425
21	T/(1-T) Rev Reqt (= 0.6455)	(6,108)	(2,332)	(2,568)	(446)	(2,090)	(32)	(1,160)	(312)	(19)	0	(829)	(39)	(10)
22	Total Proposed Rate Rev Reqt	167,636	65,968	64,712	11,915	52,012	784	34,025	7,766	525	0	25,734	1,050	1,880
	(3) Equal Return Rev													
23	T/(1-T) Rev Reqt (= 0.6455)	(6,108)	(2,332)	(2,568)	(446)	(2,090)	(32)	(1,160)	(312)	(19)	0	(829)	(39)	(10)
27	Equal Net Oper Exp Rev Reqt	137,093	52,868	52,303	9,611	42,038	654	29,698	6,646	431	0	22,621	759	1,464
28	Equal Rate of Ret (9.20%) x Rate Base	22,273	9,160	8,668	1,606	6,958	103	4,085	1,040	62	0	2,983	136	224
29	- AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Net Return	22,273	9,160	8,668	1,606	6,958	103	4,085	1,040	62	0	2,983	136	224
31	1/(1-T) Rev Reqt (= 1.6455)	36,652	15,073	14,263	2,644	11,450	169	6,723	1,711	103	0	4,909	224	369
32	Net Equal-Ret Rate Rev-Reqt (R99)	167,636	65,610	63,998	11,808	51,399	791	35,260	8,045	514	0	26,701	944	1,824
33	Tot Oper Rev - Equal	207,239	79,804	79,933	14,456	64,477	999	44,266	10,145	653	0	33,469	1,174	2,061
34	- Total Operating Exp	176,696	67,063	68,237	12,259	55,116	862	38,704	8,746	570	0	29,388	990	1,702
35	Equal Op Inc Before Inc Tax	30,543	12,741	11,695	2,197	9,361	138	5,562	1,399	83	0	4,080	184	360
36	Equal Taxable Net Income	21,081	9,130	7,718	1,506	6,123	89	3,765	916	54	0	2,796	123	345
37	Equal Fed & State Inc Tax	8,270	3,582	3,028	591	2,402	35	1,477	359	21	0	1,097	48	135
38	Proposed Common Return	14,405	5,924	5,606	1,039	4,500	66	2,642	672	40	0	1,929	88	145
39	Equal Return on Common	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%	11.49%	0.00%	11.49%	11.49%	11.49%

			1=2+3+6	2											
			1=2+6+9+30	2=3 to 5	11=12 to 14	12	13	14	15=16 to 19	16	17	18	19	30=31+32	33=34 to 36
			1=2+6+9+10	2=3 to 5	12=13 to 15	13	14	15	16=17 to 20	17	18	19	20	31=32+33	34=35 to 37
				0	0				0					0	0
INTERNAL ALLOCATORS		Intern:	**ND**	**Res Tot**	**Sm Tot**	**Sm Non-D**	**Second**	**Primary**	**Lg Tot**	**Second**	**Primary**	**Trans**	**Interrupt**	**Muni Tot**	**Ltg Tot**
1	**Rate Base: Col %'s**	**BASE-COL**	**1100.000%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**
			100.000%												
2	50% Cus, 50% Prod Plt	C11P10	100.000%	59.258%	26.721%	8.207%	18.242%	0.272%	12.229%	2.645%	0.175%	0.000%	9.410%	0.396%	1.396%
3	Peaking Plant Capacity	D10C	100.000%	32.814%	43.791%	7.331%	35.910%	0.550%	22.466%	5.262%	0.323%	0.000%	16.881%	0.667%	0.262%
4	100% Sum/Win Dmd, 0% Ene	D100E0	100.000%	30.236%	45.943%	7.576%	37.791%	0.577%	23.115%	5.531%	0.336%	0.000%	17.248%	0.706%	0.000%
5	61% Sum/Win Dmd, 39% Ene	D62E38	100.000%	36.841%	44.591%	7.316%	36.700%	0.575%	17.399%	5.638%	0.359%	0.000%	11.402%	0.670%	0.498%
6	Labor w/o (or w/) A&G	LABOR	100.000%	43.289%	36.353%	7.776%	28.150%	0.427%	18.362%	4.214%	0.264%	0.000%	13.885%	0.525%	1.471%
7	Net Plant In Service	NEPIS	100.000%	41.914%	38.602%	7.253%	30.898%	0.452%	17.914%	4.590%	0.273%	0.000%	13.051%	0.609%	0.961%
8	Dis O&M w/o Sup & Misc	OXDTS	100.000%	51.447%	28.117%	7.459%	20.419%	0.240%	11.361%	2.651%	0.120%	0.000%	8.590%	0.501%	8.574%
9	Other Prod Capac O&M	OXOPD	100.000%	33.799%	41.686%	6.940%	34.212%	0.534%	23.491%	5.275%	0.337%	0.000%	17.878%	0.619%	0.405%
10	O&M w/o Reg Ex & OXTS-Alloc'd A&G	OXTS	100.000%	37.519%	38.606%	6.896%	31.218%	0.492%	22.418%	4.999%	0.329%	0.000%	17.090%	0.553%	0.904%
11	Production Plant	P10	100.000%	34.519%	40.146%	6.653%	32.970%	0.523%	24.241%	5.285%	0.348%	0.000%	18.608%	0.584%	0.510%
12	Total P51 & P61A	P5161A	100.000%	33.878%	41.516%	6.908%	34.075%	0.533%	23.574%	5.276%	0.339%	0.000%	17.959%	0.615%	0.417%
13	Distribution Plant	P60	100.000%	57.446%	27.492%	7.522%	19.768%	0.202%	11.411%	2.462%	0.086%	0.000%	8.862%	0.521%	3.130%
14	Distr Substn Plant	P61	100.000%	40.159%	37.823%	6.039%	31.309%	0.475%	20.381%	4.617%	0.293%	0.000%	15.471%	0.604%	1.033%
15	Line Transformer Plant	P68	100.000%	50.267%	34.130%	6.383%	27.717%	0.030%	14.514%	3.432%	0.019%	0.000%	11.063%	0.710%	0.379%
16	Services Plant	P69	100.000%	78.414%	15.322%	3.220%	12.102%	0.000%	5.897%	1.295%	0.000%	0.000%	4.602%	0.367%	0.000%
17	Dist Plt Overhead Lines	POL	100.000%	49.655%	29.655%	6.894%	22.537%	0.224%	13.129%	2.993%	0.135%	0.000%	10.001%	0.520%	7.041%
18	Real Est & Property Tax	PT0	100.000%	43.089%	37.023%	7.236%	29.364%	0.423%	17.839%	4.338%	0.251%	0.000%	13.250%	0.596%	1.452%
19	Produc, Trans & Distrib	PTD	100.000%	40.029%	38.568%	7.024%	31.078%	0.466%	19.738%	4.752%	0.293%	0.000%	14.693%	0.594%	1.071%
20	Dist Plt Undground Lines	PUL	100.000%	67.721%	23.941%	8.296%	15.584%	0.062%	7.618%	1.758%	0.033%	0.000%	5.828%	0.446%	0.273%
21	**Rev w/o Reg, etc: Col %**	**R02-COL**	**1100.000%**	**N/A**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**
			100.000%	**44.36%**	**44.55%**	**7.48%**	**36.58%**	**0.49%**	**7.48%**	**3.18%**	**0.33%**	**0.00%**	**3.97%**	**0.98%**	**2.64%**
			100.000%	**42.10%**	**40.86%**	**7.51%**	**32.92%**	**0.44%**	**14.97%**	**3.91%**	**0.31%**	**0.00%**	**10.76%**	**0.90%**	**1.16%**
22	Rate Base (Non-Column)	RTBASE	100.000%	41.125%	38.915%	7.213%	31.241%	0.462%	18.342%	4.667%	0.280%	0.000%	13.394%	0.610%	1.007%
23	Stratified Hydro Baseload	STRATH	100.000%	34.554%	40.070%	6.639%	32.909%	0.522%	24.278%	5.286%	0.348%	0.000%	18.644%	0.582%	0.515%
24	Transmission & Distrib	TD	100.000%	49.310%	35.911%	7.650%	27.890%	0.371%	12.151%	3.855%	0.200%	0.000%	8.097%	0.610%	2.017%
25	Labor Dis w/o Sup & Eng	ZDTS	100.000%	54.050%	28.883%	8.129%	20.483%	0.271%	11.320%	2.630%	0.121%	0.000%	8.569%	0.520%	5.228%

			1=2+6+9+10	2=3 to 5	12=13 to 15	13	14	15	16=17 to 20	17	18	19	20	31=32+33	34=35 to 37
				0	0				0					0	0
INTERNAL DATA			**ND**	**Res Tot**	**Sm Tot**	**Sm Non-D**	**Second**	**Primary**	**Lg Tot**	**Second**	**Primary**	**Trans**	**Interrupt**	**Muni Tot**	**Ltg Tot**
26	Labor w/o A&G	LABOR(S)	12,354	5,348	4,491	961	3,478	53	2,269	521	33	0	1,715	65	182
27	Dis O&M w/o Sup, Cust Install & Misc	OXDTS	4,459	2,294	1,254	333	910	11	507	118	5	0	383	22	382
28	O&M w/o Reg Ex & OXTS-Alloc'd A&G	OXTS	145,610	54,632	56,214	10,042	45,457	716	32,643	7,279	480	0	24,885	805	1,316
29	Total P51 & P61A	P5161A	2,774	940	1,152	192	945	15	654	146	9	0	498	17	12
30	Produc, Trans & Distrib	PTD	568,463	227,550	219,247	39,932	176,665	2,650	112,201	27,015	1,664	0	83,522	3,375	6,090
31	Transmission & Distrib	TD	211,759	104,419	76,045	16,200	59,060	785	25,732	8,163	423	0	17,146	1,292	4,271
32	Labor Dis w/o Sup & Eng, Cust Install	ZDTS	2,235	1,208	645	182	458	6	253	59	3	0	191	12	117

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
Compliance Class Cost of Service Study

(Comm / Indus By Size)

Case No. PU-07-____
Exhibit No. ______(PJZ-1)
Schedule 4

EXTERNAL ALLOCATORS	Extern:	ND	Res Tot	Sm Tot	Sm Non-D	Second	Primary	Lg Tot	Second	Primary	Trans	Interrupt	Muni Tot	Ltg Tot
		1=2+6+9+10	2=3 to 5	12=13 to 15	13	14	15	16=17 to 2(	17	18	19	20	31=32+33	34=35 to 37
1 Customers - Ave Monthly	C11	100.00%	84.00%	13.30%	9.76%	3.51%	0.02%	0.22%	0.00%	0.00%	0.00%	0.21%	0.21%	2.28%
2 Cust Acctg Wtg Factor	C11WA	100.00%	78.34%	20.30%	13.69%	6.57%	0.04%	1.00%	0.01%	0.00%	0.00%	0.99%	0.00%	0.35%
3 Mo Cus Wtd By Mtr Invest	C12WM	100.00%	59.81%	27.86%	19.70%	7.09%	1.07%	11.53%	0.02%	0.06%	0.00%	11.46%	0.73%	0.06%
4 Sec & Pri Customers	C61PS	100.00%	85.81%	13.65%	10.02%	3.61%	0.02%	0.22%	0.00%	0.00%	0.00%	0.22%	0.21%	0.10%
5 C62Sec, w/o Ltg & C/I Underground	C62NL	100.00%	94.58%	5.26%	3.87%	1.39%	0.00%	0.08%	0.00%	0.00%	0.00%	0.08%	0.08%	0.00%
6 Secondary Customers	C62Sec	100.00%	85.84%	13.64%	10.03%	3.61%	0.00%	0.21%	0.00%	0.00%	0.00%	0.20%	0.21%	0.10%
7 Summer Peak Resp KW	D10S	100.00%	30.24%	45.94%	7.58%	37.79%	0.58%	23.11%	5.53%	0.34%	0.00%	17.25%	0.71%	0.00%
8 Transmission Demand %	D10T	100.00%	37.89%	48.04%	7.86%	39.57%	0.61%	12.89%	5.85%	0.36%	0.00%	6.68%	0.74%	0.44%
9 Winter Peak Resp KW	D10W	100.00%	40.46%	37.41%	6.61%	30.33%	0.47%	20.54%	4.46%	0.29%	0.00%	15.79%	0.55%	1.04%
10 Dmd Equiv of E8760	D8760	100.00%	35.11%	38.89%	6.42%	31.96%	0.51%	24.85%	5.29%	0.36%	0.00%	19.20%	0.56%	0.60%
11 Sec, Pri & TT, Class Coin kW @ Subst	D60Sub	100.00%	40.27%	37.71%	6.02%	31.22%	0.47%	20.37%	4.60%	0.29%	0.00%	15.48%	0.60%	1.05%
12 Sec & Pri, Cl Coin kW (no Min Sys; adj	D61PS	100.00%	30.21%	43.83%	6.08%	37.19%	0.56%	24.31%	5.49%	0.35%	0.00%	18.48%	0.71%	0.94%
13 D62Sec, w/o Ltg & C/I Underground	D62NLL	100.00%	35.43%	42.08%	1.50%	40.58%	0.00%	21.36%	4.74%	0.00%	0.00%	16.63%	1.12%	0.00%
14 Sec, Class Coin kW (w/o Min Sys kW)	D62SecL	100.00%	27.08%	47.67%	3.84%	43.83%	0.00%	23.67%	5.66%	0.00%	0.00%	18.02%	1.06%	0.52%
15 Direct Assign Street Lighting	DASL	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
16 On + Off Sales MWH	E8760	100.00%	35.11%	38.89%	6.42%	31.96%	0.51%	24.85%	5.29%	0.36%	0.00%	19.20%	0.56%	0.60%
17 Street Lighting (Dir Assign)	P73	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
18 Present Rev	R01	100.00%	39.22%	38.69%	7.05%	31.16%	0.48%	20.22%	4.65%	0.32%	0.00%	15.25%	0.60%	1.28%

APPLIED EXTERNAL DATA (BIG or LITTLE)		ND	Res Tot	Sm Tot	Sm Non-D	Second	Primary	Lg Tot	Second	Primary	Trans	Interrupt	Muni Tot	Ltg Tot
		1=2+6+9+10	2=3 to 5	12=13 to 15	13	14	15	16=17 to 2(	17	18	19	20	31=32+33	34=35 to 37
			0	0				0					0	0
19 Customers - B Basis	C10	85,336	73,223	11,652	8,553	3,080	18	190	4	1	0	185	182	89
20 Cust - Ave Monthly (C10-Area Lt)	C11	87,633	73,609	11,652	8,553	3,080	18	190	4	1	0	185	182	2,000
21 Mo Cus Wtd By Cus Acct	C11WA	93,709	73,416	19,027	12,830	6,160	37	942	12	3	0	927	0	325
22 Cust Acctg Wtg Factor	C11WAF	25.10	2.50	5.50	1.50	2.00	2.00	14.00	3.00	3.00	3.00	5.00	0.00	3.10
23 Cust-Ave Mo (C11 w/ Dir Assign St Ltg	C12	85,645	73,609	11,652	8,553	3,080	18	190	4	1	0	185	182	12
24 Mo Cus Wtd By Mtr Invest	C12WM	6,164,138	3,686,694	1,717,633	1,214,218	437,281	66,134	711,032	1,144	3,601	0	706,287	45,186	3,594
25 Meter Invest / Cust Factor	C12WMF	16,054	284	3,885	142	142	3,601	11,299	286	3,601	3,601	3,811	286	299
26 Sec & Pri Customers	C61PS	85,336	73,223	11,652	8,553	3,080	18	190	4	1	0	185	182	89
27 C62Sec, w/o Ltg & C/I Underground	C62NL	77,421	73,223	4,072	2,994	1,078	0	62	1	0	0	61	64	0
28 Secondary Customers	C62Sec	85,306	73,223	11,633	8,553	3,080	0	178	4	0	0	174	182	89
29 Summer Peak Resp KW	D10S	454,961	137,561	209,025	34,467	171,934	2,624	105,164	25,165	1,528	0	78,471	3,211	0
30 Dmd (D10S x Fact + D10W)/1000	D10T	10,000,000	3,789,197	4,804,254	785,929	########	61,218	########	584,676	36,130	0	667,924	73,922	43,897
31 Winter Peak Resp KW	D10W	388,237	157,068	145,240	25,649	117,762	1,829	79,751	17,324	1,109	0	61,317	2,148	4,030
32 Dmd Equiv of E20	D20	3,136,445	1,084,866	1,215,858	199,431	########	16,194	796,420	169,321	11,516	0	615,583	17,177	22,123
33 Sec, Pri & TT, Class Coin kW @ Subst	D60Sub	586,281	236,103	221,073	35,268	183,033	2,771	119,434	26,947	1,707	0	90,781	3,537	6,134
34 Sec & Pri, Class Coin kW (w/o Min Sys	D61PS	491,152	148,378	215,288	29,883	182,635	2,769	119,409	26,946	1,706	0	90,757	3,473	4,604
35 D62Sec, w/o Ltg & C/I Underground	D62NLL	1,834,242	649,891	771,885	27,524	744,361	0	391,876	86,863	0	0	305,013	20,590	0
36 Sec, Class Coin kW (w/o Min Sys kW)	D62SecL	521,484	198,504	212,519	29,883	182,635	0	102,383	26,946	0	0	75,437	3,473	4,604
37 Annual Billing kW	D99	3,530	0	2,159	0	2,127	31	1,313	248	17	0	1,048	58	0
38 Summer Billing kW	D99S	1,222	0	730	0	719	11	471	91	6	0	374	22	0
39 Winter Billing kW	D99W	2,308	0	1,429	0	1,408	21	843	157	11	0	674	37	0
40 Non-Coinc Pk Second	DN-Sec	4,039,999	649,891	2,205,385	78,639	########	0	########	248,180	0	0	871,465	58,829	6,249
41 Energy At Gener MWH	E10	2,394,439	849,131	903,977	146,439	745,374	12,164	608,391	128,679	8,899	0	470,813	12,702	20,238
42 On Peak Wtg Factor %	E11	NA	NA	133.54%	46.68%	44.11%	42.74%	118.35%	40.75%	37.94%	0.00%	39.67%	N/A	N/A
43 Wtd On + Off Sales MWH	E20	3,136,445	1,084,866	1,215,858	199,431	########	16,194	796,420	169,321	11,516	0	615,583	17,177	22,123
44 MWH Sales @ Gen	E99	2,217,924	782,202	836,541	134,951	690,197	11,393	568,703	119,144	8,335	0	441,224	11,761	18,717

ALLOCATOR CONSTANTS				
1	% D10 O&M Econ Develop	Econ Dev Dmd		
2	% D10 O&M CIP/DSM	CIP Dmd		
3	On Peak Energy Wtg Factor For E20	ONPKWF		
4	APL Inv In OH Lines: Dir Assignable	**POLAPL**		
5	Summer Factor	SFAC		
6	Overhead Lines St Ltg Comp Owned	**QQOSL1**		
7	Overhead Lines Area Lighting	**QQOSL2**		
8	Overhead Lines Primary - Customer	**QQ64C**		
9	Overhead Lines Primary - Demand	**QQ64D**		
10	Overhead Lines Secondary - Customer	**QQ65C**		
11	Overhead Lines Secondary - Demand	**QQ65D**		
12	Overhead Total			
13	Underground Primary - Customer	**QQ66C**		
14	Underground Primary - Demand	**QQ66D**		
15	Underground Secondary - Customer	**QQ67C**		
16	Underground Secondary - Demand	**QQ67D**		
17	Underground Total			
18	Line Trans Secondary - Customer	**QQ68C**		
19	Line Trans Secondary - Demand	**QQ68D**		
20	Line Trans Primary - Demand	**QQ68P**		
21	Line Trans Total			
22	Services - Customer	**QQ69C**		
23	Services - Demand	**QQ69D**		
24	Services Total			
25	Stratified Nuclear Baseload (JCOSS on	**STRNBL**		
26	Stratified Fossil Baseload (JCOSS only	**STRFBL**		
27	Stratified Hydro Baseload	**STRHBL**		
CALCULATED CONSTANTS				
28	Net Overhead Lines Investment	**QPOLS**		
29	Ovhd Lines St Ltg Co - Assignable	**QQSL1**		
30	Ovhd Lines Area Ltg - Assignable	**QQSL2**		
31	Ovhd St Lt + Area Lt + Dir Assign	**QQSLTOT**		
32	**Peaking Factor For Purchased Power**			
33	Total Proposed Retail Revenue			
34	Ratio: Prop vs Pres Retail Revenue			
35	Minn Total State & Fed Tax Rate	**TAXRATE**		
			Cost	**Ratio**
36	**Long Term Debt**		6.79%	45.61%
37	**Short Term Debt**		5.74%	2.62%
38	**Preferred Stock**		0.00%	0.00%
39	**Equity**		11.50%	51.77%
CALCULATED CONSTANTS				
40	Proposed Overal Return			
41	Interest Exp Factor	**DETFACT**		
42	Debt Ratio	**DETRATIO**		
43	Embedded Cost of Debt	**DETCOST**		
44	Rev Increase Percent	INCRPCT		
45	1 / (1 - Tax Rate) Factor	**ONEOVER**		
46	Tax Rate / (1 - Tax Rate) Factor	**TAXOVER**		

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
Compliance Class Cost of Service Study
Allocator Index

Case No. PU-07-______
Exhibit No. ______(PJZ-1)
Schedule 4

Alloc	Expense / Revnue	Pg	Ln
(R16C); R02	Incr Late Pay - Prop	7	24
(total); BASE	Pres Preliminary Return	11	41A
(total); BASE	Prop Preliminary Return	11	41B
C11	Connection Charges	7	13
C11	Connect Fees, Cus Adv	11	14
C11P10	Cust Assist Exp - Non-CIP	8	29
C11P10	Instructional Advertising	8	31
C11P10	Sales Expense	12	45
C11P10	Service & Inform	12	47
C11WA	Customer Accounting	8	13
C11WA	Cust Accounting	12	44
C12WM	Meters	4	41
C12WM	Meters	5	21
C12WM	Meters	5	48
C12WM	Meters	6	21
C12WM	Meters	8	7
C12WM	Meters	9	20
C12WM	Meters	9	45
C12WM	Meters	10	20
C12WM	Meters	10	21
C12WM	Meters	11	21
C12WM	Meters	12	21
C12WM	Meter	12	39
C61PS	Primary Customer	4	20
C61PS	Primary Customer	4	28
C62NL	Second Customer	4	39
C62Sec	Second Customer	4	23
C62Sec	Second Customer	4	31
C62Sec	Second Customer	4	36
D100E0	Econ Development	8	14
D10C	Interruptible Capacity Costs	2	7
D10C	Interruptible Capacity Costs	3	7
D10C	Gen Step Up Peak	4	8
D10C	Peaking Plant	5	1
D10C	Decom Int Peaking	5	2
D10C	Gen Step Up Peak	5	6
D10C	Peaking Plant	5	28
D10C	Gen Step Up Peak	5	33
D10C	Peaking Plant	6	1
D10C	Gen Step Up Peak	6	6
D10C	Purchases: Cap Peak	7	29
D10C	Capacity Peaking	7	38
D10C	Peaking Plant	9	1
D10C	Gen Step Up Peak	9	5
D10C	Peaking Plant	9	26
D10C	Gen Step Up Peak	9	30
D10C	Peaking Plant	10	1
D10C	Gen Step Up Peak	10	5
D10C	Gen Step Up Peak	10	6
D10C	Peaking Plant	10	29
D10C	Peaking Plant	11	1
D10C	Gen Step Up Peak	11	6
D10C	Peaking Plant	12	1
D10C	Gen Step Up Peak	12	6

Alloc	Expense / Revnue	Pg	Ln
D10S	Summer Peak	4	1
D10T	Bulk Transmission	4	10
D10T	Bulk Transmission	4	15
D10T	Bulk Transmission	5	8
D10T	Bulk Transmission	5	13
D10T	Bulk Transmission	5	35
D10T	Bulk Transmission	5	40
D10T	Bulk Transmission	6	8
D10T	Bulk Transmission	6	13
D10T	Interchg Tr Bulk Supply	7	10
D10T	Joint Op Agree-Other PSCo Rev	7	15
D10T	Misc Ancillary Trans Rev	7	17
D10T	MISO	7	18
D10T	Other	7	19
D10T	Transmission Exp	7	44
D10T	Load Dispatching	8	2
D10T	Bulk Transmission	9	7
D10T	Bulk Transmission	9	12
D10T	Bulk Transmission	9	32
D10T	Bulk Transmission	9	37
D10T	Bulk Transmission	10	8
D10T	Bulk Transmission	10	12
D10T	Bulk Transmission	10	13
D10T	Bulk Transmission	10	32
D10T	Bulk Transmission	11	8
D10T	Bulk Transmission	11	13
D10T	Bulk Transmission	12	8
D10T	Bulk Transmission	12	13
D10T	Bulk Power Subs	12	31
D10T	Load Dispatch	12	34
D10W	Winter Peak	4	2
D60Sub	Distrib Function	4	11
D60Sub	Distrib Function	4	16
D60Sub	Distrib Function	5	9
D60Sub	Distrib Function	5	14
D60Sub	Distrib Function	5	36
D60Sub	Distrib Function	5	41
D60Sub	Distrib Function	6	9
D60Sub	Distrib Function	6	14
D60Sub	Distrib Function	9	8
D60Sub	Distrib Function	9	13
D60Sub	Distrib Function	9	33
D60Sub	Distrib Function	9	38
D60Sub	Distrib Function	10	8
D60Sub	Distrib Function	10	9
D60Sub	Distrib Function	10	13
D60Sub	Distrib Function	10	14
D60Sub	Distrib Function	11	9
D60Sub	Distrib Function	11	14
D60Sub	Distrib Function	12	9
D60Sub	Distrib Function	12	14
D62E38	CIP Performance	7	6
D62E38	CIP Total	8	30
D61PS	Primary Capacity	4	19

Alloc	Expense / Revnue	Pg	Ln
D61PS	Primary Capacity	4	27
D61PS	Primary	4	34
D62NLL	Second Capacity	4	38
D62SecL	Second Capacity	4	22
D62SecL	Second Capacity	4	30
D62SecL	Second Capacity	4	35
D8760	Base Load	4	4
D8760	Nuclear Fuel	4	5
D8760	Gen Step Up Base	4	7
D8760	Nuclear Fuel	5	2
D8760	Decom Int Baseload	5	3
D8760	Base Load	5	3
D8760	Gen Step Up Base	5	5
D8760	Base Load	5	29
D8760	Nuclear Fuel	5	30
D8760	Gen Step Up Base	5	32
D8760	Base Load	6	2
D8760	Nuclear Fuel	6	3
D8760	Gen Step Up Base	6	5
D8760	Purchases: Cap Base	7	30
D8760	Capacity Baseload	7	39
D8760	Base Load	9	2
D8760	Gen Step Up Base	9	4
D8760	Base Load	9	27
D8760	Gen Step Up Base	9	29
D8760	Nuclear Fuel	10	2
D8760	Base Load	10	3
D8760	Gen Step Up Base	10	4
D8760	Gen Step Up Base	10	5
D8760	Base Load	10	30
D8760	Nuclear Fuel	11	2
D8760	Base Load	11	3
D8760	Gen Step Up Base	11	5
D8760	Nuclear Fuel Disposal	11	34
D8760	Nuclear Fuel	12	2
D8760	Base Load	12	3
D8760	Gen Step Up Base	12	5
DASL	Street Lighting	4	25
Dir Assign	Direct Assign	4	12
Dir Assign	Direct Assign	4	17
Dir Assign	Street Lighting	4	42
Dir Assign	Direct Assign	5	10
Dir Assign	Direct Assign	5	15
Dir Assign	Direct Assign	5	37
Dir Assign	Direct Assign	5	42
Dir Assign	Direct Assign	6	10
Dir Assign	Direct Assign	6	15
Dir Assign	Direct Assign	7	22
Dir Assign	Street Lighting	8	9
Dir Assign	Direct Assign	9	9
Dir Assign	Direct Assign	9	14
Dir Assign	Direct Assign	9	34
Dir Assign	Direct Assign	9	39
Dir Assign	Direct Assign	10	10

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
Compliance Class Cost of Service Study
Allocator Index

Alloc	Expense / Revnue	Pg	Ln
Dir Assign	Direct Assign	10	14
Dir Assign	Direct Assign	10	15
Dir Assign	Direct Assign	10	33
Dir Assign	Direct Assign	11	10
Dir Assign	Direct Assign	11	15
Dir Assign	Direct Assign	12	10
Dir Assign	Direct Assign	12	15
E8760	Fuel Inventory	6	27
E8760	Interchg Prod Energy	7	9
E8760	Dist Int Sales; Oth Serv	7	11
E8760	Sales For Resale	7	14
E8760	Production Assoc'd Rev	7	16
E8760	Fuel	7	28
E8760	Purchases: Other Energy	7	32
E8760	Interchg Agr Energy	7	35
E8760	Energy	7	41
E8760	Nuclear Fuel Book Burn	11	33
E8760	Other Prod - Ene	12	28
LABOR	Non-Plant Related	5	55
LABOR	Non-Plant Assets & Liab	6	33
LABOR	Salaries	8	15
LABOR	Outside Services	8	18
LABOR	Pensions & Benefits	8	20
LABOR	Injuries & Claims	8	21
LABOR	Amortizations	8	33
LABOR	Payroll Taxes	9	52
LABOR	Non - Plant Related	10	27
LABOR	Non - Plant Related	11	27
LABOR	Meals & Entertainment	11	35
LABOR	Admin & General	12	46
NEPIS	TBT Investment	4	21
NEPIS	TBT Acc Def Tax	5	54
NEPIS	Miscellaneous	6	31
NEPIS	Insurance	6	33
NEPIS	Property Insurance	8	19
NEPIS	TBT Defer Inc Tax	10	26
NEPIS	TBT Misc Net Exp	10	28
NEPIS	TBT Misc Net Exp	11	7
NEPIS	TBT Defer Inc Tax	11	26
OXDTS	Customer Install'n	8	8
OXDTS	Miscellaneous	8	10
OXDTS	Miscellaneous	12	42
OXOPD	Other Prod - Cap	12	27
OXTS	Office Supplies	8	16
OXTS	Admin Transfer Credit	8	17
OXTS	General Advertising	8	23
OXTS	Contributions	8	24
OXTS	Misc General Exp	8	25
OXTS	Rents	8	26
OXTS	Maint of General Plant	8	27
P10	Production	6	28
P10	Interchg Prod Capacity	7	8
P10	Interchg Agr Capacity	7	34
P5161A	Stepup Subtrans	12	30

Alloc	Expense / Revnue	Pg	Ln
P61	Substations	8	3
P61	Substation	12	35
P68	Line Transformers	5	19
P68	Line Transformers	5	46
P68	Line Transformers	6	19
P68	Line Transformers	8	6
P68	Line Transformers	9	18
P68	Line Transformers	9	43
P68	Line Transformers	10	18
P68	Line Transformers	10	19
P68	Line Transformers	11	19
P68	Line Transformers	12	19
P68	Line Transformer	12	38
P69	Services	5	20
P69	Services	5	47
P69	Services	6	20
P69	Services	9	19
P69	Services	9	44
P69	Services	10	19
P69	Services	10	20
P69	Services	11	20
P69	Services	12	20
P73	Street Lighting	5	22
P73	Street Lighting	5	49
P73	Street Lighting	6	22
P73	Street Lighting	9	21
P73	Street Lighting	9	46
P73	Street Lighting	10	21
P73	Street Lighting	10	22
P73	Street Lighting	11	22
P73	Street Lighting	12	22
P73	Street Lighting	12	41
POL	Overhead Lines	5	17
POL	Overhead Lines	5	44
POL	Overhead Lines	6	17
POL	Dist Overhd Line Rent	7	12
POL	Overhead Lines	8	4
POL	Rents (Pole Attachmts)	8	11
POL	Overhead Lines	9	16
POL	Overhead Lines	9	41
POL	Overhead Lines	10	17
POL	Overhead Lines	10	35
POL	Overhead Lines	11	17
POL	Overhead Lines	12	17
POL	Overhead Lines	12	36
PROREV	Proposed Rate Revenue	7	2
PT0	Working Cash	6	34
PTD	General Plant	4	44
PTD	Electric Common	4	45
PTD	General Plant	5	24
PTD	Electric Common	5	25
PTD	General Plant	5	51
PTD	Electric Common	5	52
PTD	General Plant	6	24

Alloc	Expense / Revnue	Pg	Ln
PTD	Electric Common	6	25
PTD	General Plant	9	23
PTD	Electric Common	9	24
PTD	General Plant	9	48
PTD	Electric Common	9	49
PTD	General Plant	10	24
PTD	Electric Common	10	25
PTD	General Plant	10	38
PTD	Electric Common	10	39
PTD	Book Depr Cleared To Oper	11	11
PTD	Tax Capitalized Leases	11	12
PTD	General Plant	11	24
PTD	Electric Common	11	25
PTD	General Plant	12	24
PTD	Electric Common	12	25
PUL	Underground	5	18
PUL	Underground	5	45
PUL	Underground	6	18
PUL	Underground Lines	8	5
PUL	Underground	9	17
PUL	Underground	9	42
PUL	Underground	10	18
PUL	Underground	10	36
PUL	Underground	11	18
PUL	Underground	12	18
PUL	Underground Lines	12	37
R01,	Incr Misc Serv - Prop	7	23
R01; (calc)	Present Rate Revenue	7	1
R01; R02	Interdepartmental	7	3
R01; R02	Gross Earnings Tax	7	4
R01; R02	Regulatory Exp	8	22
R01; R02	Gross Earnings Tax	9	51
R16C; R02	Late Pay Chg - Pres	7	20
RTBASE	Avoided Tax Interest	11	36
RTBASE	Rev Items, Equal Alloc	13	26
STRATH	Generat Step Up	4	14
STRATH	Generat Step Up	5	12
STRATH	Generat Step Up	5	39
STRATH	Generat Step Up	6	12
STRATH	Generat Step Up	9	11
STRATH	Generat Step Up	9	36
STRATH	Generat Step Up	10	11
STRATH	Generat Step Up	10	12
STRATH	Generat Step Up	11	12
STRATH	Generat Step Up	12	12
TD	Trans & Distr	6	29
ZDTS	Supervision & Eng'rg	8	1
ZDTS	Superv & Eng	12	33
ZDTS	Cust Installation	12	40

Northern States Power Company, Minnesota Coporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
VOLTAGE DISCOUNT ANALYSIS - DEMAND ($/kW)

Case No. PU-07-_______
Exhibit No. _____(PJZ-1)
Schedule 5
Page 1 of 2

Includes losses to indicate additional billing kW low voltage customers would have at higher voltage.

		Primary Costs	
	Secondary Costs	Lines & Transformers	Distribution Substation
1. Revenue Requirement ($000s):			
(CCOSS; p. 2; lines 34,33,32)	$2,882.459	$2,061.578	$1,492.592
2. Billing KW (Workpaper attached)			
Secondary Voltage kW	3,304,606	3,304,606	3,304,606
Loss 1		0.9253	0.9388
Loss 2		0.9070	0.9070
Loss Factor	1.0000	1.0202	1.0351
Secondary With Losses	**3,304,606**	**3,371,325**	**3,420,450**
Primary Voltage kW		225,698	225,698
Loss 1			0.9388
Loss 2			0.9253
Loss Factor		1.0000	1.0146
Primary With Losses		**225,698**	**228,987**
Transmission Transformed Voltage kW			**0**
Total kW (Metered Sales + Losses)	**3,304,606**	**3,597,024**	**3,649,437**
3. Rev Reqt / kW (Line 1 / Line 2)	$0.87	$0.57	$0.41
4. Cumulative Rev Reqt/ kW	**$0.87**	**$1.45**	**$1.85**
5. Present Individual Discounts	$0.55	$0.55	$0.55
6. Cumulative Present Discount	**$0.55**	**$1.10**	**$1.65**
7. Cumulative Proposed Discount	**$0.85**	**$1.45**	**$1.85**

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008

VOLTAGE DISCOUNT ANALYSIS - ENERGY (¢/kWh)

Voltage	Loss Factor*	Percent Difference	Energy Charge	Cost-Based Discount	Proposed Discount	Present Discount
Secondary	0.9201	0.00%	5.000 ¢	0.000 ¢	0.000 ¢	0.000 ¢
Primary	0.9323	1.31%	4.934 ¢	0.066 ¢	0.070 ¢	0.050 ¢
T Transformec	0.9397	2.09%	4.895 ¢	0.105 ¢	0.100 ¢	0.060 ¢
Transmission	0.9487	3.02%	4.849 ¢	0.151 ¢	0.150 ¢	0.090 ¢

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008

Fuel Cost Rider - Service Category Ratios

Case No. PU-07-________
Exhibit No. ______(PJZ-1)
Schedule 6
Page 1 of 1

		Residential	C&I Non-Dmd	C&I Demand			Outdoor Lighting	TOTAL
	STEP 1: DEVELOP CLASS RATIOS							
1.	Assigned Test-Year Marginal Energy Cost *	$42,239,366	$7,771,796	$68,911,803			$716,727	$119,639,692
2.	Test-Year Energy (at Generator) (MWh)	849,131	147,459	1,377,611			20,238	2,394,439
3.	Average Load-Weighted Marginal Energy Cost Per kWh (1)/(2)	$49.7442	$52.7050	$50.0227			$35.4153	$49.9657
4.	**Class Ratio (Class Unit Cost / System Unit Cost)**	**0.9956**	**1.0548**	**1.0011**			**0.7088**	
	STEP 2: DE-AVERAGE C&I DEMAND CLASS RATIOS							
					TOD On-Peak	**TOD Off-Peak**		
5.	Ratio of On- to Off-Peak Energy Charges				1.70			
6.	C&I Demand Class On/Off Peak Percentage				0.4224	0.5776		
7.	C&I Demand TOD On-Peak Ratio = 1 / (0.4224 + (0.5776 / 1.700)) **				**1.3121**			
8.	C&I Demand TOD Off-Peak Ratio = 1 / ((1.7000 x 0.4224) + 0.5776)) **					**0.7718**		
				Non-TOD				
9.	C&I Non-TOD On-Peak Weighting			0.4421				
10.	C&I Non-TOD Off-Peak Weighting			0.5579				
11.	C&I Demand Non-TOD Ratio = (0.44210 x 1.3121) + (0.55790 x 0.7718)			**1.0107**				
	STEP 3: DEVELOP SERVICE CATEGORY RATIOS							
12.	**SERVICE CATEGORY RATIOS** Residential, C&I Non-Demand & Lighting = Class Ratio (Step1) C&I Demand = Class Ratio (Step 1) x TOD Ratio (Step 2)	**0.9956**	**1.0548**	**1.0118**	**1.3135**	**0.7726**	**0.7088**	

* E8760 Allocator = Sum of Hourly System Marginal Costs times Class Hourly Loads

** TOD Ratio Equations is derived from the following:

Weighted Average Energy Charge = (0.4224 x On Peak Energy Charge) + (0.5776 x Off Peak Energy Charge)
Where 0.4224 and 0.5776 are C&I Demand class on- and off-peak % respectively

Xcel Energy

Distributed Generation Interconnection Manual

Interconnection Process for Distributed Generation Systems

Interconnection Agreement
For the Interconnection of
Extended Parallel Distributed Generation Systems

Application to Interconnect Form

Engineering Data Submittal Form

Interconnection Requirements for Extended Paralleled Distribution Generation Systems

Version Date
September 14, 2007

Interconnection Process for Distributed Generation Systems

Introduction

This document has been prepared to explain the process established to interconnect a Generation System with the Xcel Energy (Company) electric distribution system. This document covers the interconnection process for all types of Generation Systems that are rated 10 MWs or less of total generation Nameplate Capacity; are planned for interconnection with the Company's distribution system; are not intended for wholesale transactions; and are not anticipated to affect the transmission system. This document does not discuss the interconnection Technical Requirements, which are covered in the "Interconnection Requirements for Extended Paralleled Distribution Generation Systems" document. This interconnection requirements document also provides definitions and explanations of the terms utilized within this document. To interconnect a Generation System with the Company, several steps must be followed. This document outlines those steps and the Parties' responsibilities. At any point in the process, if there are questions, please contact the Generation Interconnection Coordinator at the Company. Since this document has been developed to provide an interconnection process that covers a very diverse range of Generation Systems, the process may appear to be very involved and cumbersome. For many Generation Systems, the process is streamlined and provides an easy path for interconnection.

The promulgation of interconnection standards for Generation Systems must be done in the context of a reasonable interpretation of the boundary between state and federal jurisdiction. The Federal Energy Regulatory Commission (FERC) has asserted authority in the area, at least as far as interconnection at the transmission level is concerned. This, however, leaves open the question of jurisdiction over interconnection at the distribution level. The Midwest Independent System Operator's (MISO) FERC Electric Tariff, (first revised volume 1, August 23,2001) Attachment R (Generator Interconnection Procedures and Agreement) states in Section 2.1:

"Any existing or new generator connecting at transmission voltages, sub-transmission voltages, or distribution voltages, planning to engage in the sale for resale of wholesale energy, capacity, or ancillary services requiring transmission service under the Midwest ISO OATT must apply to the Midwest ISO for interconnection service".

Further in Section 2.4 it states:

"A Generator not intending to engage in the sale of wholesale energy, capacity, or ancillary services under the Midwest ISO OATT, that proposes to interconnect a new generating facility to the distribution system of a Transmission Owner or local distribution utility interconnected with the Transmission System shall apply to the Transmission Owner or local distribution utility for interconnection".

It goes on further to state:

"Where facilities under the control of the Midwest ISO are affected by such interconnection, such interconnections may be subject to the planning and operating protocols of the Midwest ISO...."

Through discussions with MISO personnel and as a practical matter, if the Generation System Nameplate Capacity is not greater in size than the minimum expected load on the distribution substation that is feeding the proposed Generation System, and the Generation System's energy is not being sold on the wholesale market, then that installation may be considered as not "affecting" the transmission system and the interconnection may be considered to be governed by this process. If the Generation System will be selling energy on the wholesale market or the Generation System's total Nameplate Capacity is greater than the expected distribution substation's minimum load, then the Applicant shall contact MISO (Midwest Independent System Operator) and follow their procedures.

FERC has issued a rule for interconnecting generation facilities to distribution systems as part of their Small Generator Interconnection Procedures (SGIP). This rule covers facilities from 0 to 20 MW. If a distribution connected facility requires MISO involvement as discussed above, it probably will fall under FERC jurisdiction and will need to be interconnected under the FERC SGIP rules.

General Information

A) Definitions

1) "Applicant" is defined as the person or entity who is requesting the interconnection of the Generation System with the Company and is responsible for ensuring that the Generation System is designed, operated, and maintained in compliance with the Technical Requirements.

2) "Area EPS" is the area electric power system that is also referred to as the Company electric distribution system in this document.

3) "Company" is defined as an electric power system (EPS) that serves a Local EPS. Note: Typically, the Company has primary access to public rights-of-way, priority crossing of property boundaries, etc.

4) "Company Operator" is the entity or group who operates the Company's electric distribution system.

5) "Dedicated Facilities" is the equipment that is installed due to the interconnection of the Generation System and not required to serve other Company customers.

6) "Distribution System" is the Company facilities that are not part of the Company Transmission System or any Generation System.

7) "Extended Parallel" means the Generation System is designed to remain connected with the Company for an extended period.

8) "Generation" is defined as any device producing electrical energy; i.e., rotating generators driven by wind, steam turbines, internal combustion engines, hydraulic turbines, solar, fuel cells, etc.; or any other electric producing device, including energy storage technologies.

9) "Generation Interconnection Coordinator" is the person or persons designated by the Company Operator to provide a single point of coordination with the Applicant for the generation interconnection process. For most installations, this is the Area Engineer assigned to the area of the proposed interconnection.

10) "Generation System" is the interconnected generator(s), controls, relays, switches, breakers, transformers, inverters and associated wiring and cables, up to the Point of Common Coupling.

11) "Interconnection Customer" is the party or parties who will own/operate the Generation System and are responsible for meeting the requirements of the agreements and Technical Requirements. This could be the Generation System applicant, installer, owner, designer, or operator.

12) "Local EPS" is an electric power system (EPS) contained entirely within a single premises or group of premises.

13) "Nameplate Capacity" is the total nameplate capacity rating of all the Generation included in the Generation System. For this definition, the "standby" and/or maximum rated kW capacity on the nameplate shall be used.

14) "Open Transfer" is a method of transferring the local loads from the Company to the generator such that the generator and the Company are never connected together.

15) "Point of Common Coupling" is the point where the Local EPS or Generation Facility is connected to the Company's distribution system.

16) "Quick Closed" is a method of generation transfer that parallels for less than 100 msec with the Company and has utility grade timers that limit the parallel duration to less then 100 msec with the Company.

17) "Quick Open" is a method of generation transfer that does not parallel with the Company and has a brief open interval, typically about 100 msec.

18) Soft Loading Transfer is a method of generation load transfer that parallels for typically less than 2 minutes to gradually transfer load between the generator and the Company.

19) "State" is the state wherein the interconnected generator is located.

20) "Technical Requirements" "is the Company "Interconnection Requirements for Extended Paralleled Distribution Generation Systems".

21) "Transmission System" means those facilities as defined by using the guidelines established by FERC.

B) Dispute Resolution

The following is the dispute resolution process to be followed for problems that occur with the implementation of this process.

Each Party agrees to attempt to resolve all disputes arising hereunder promptly, equitably, and in a good faith manner. In the event a dispute arises under this process, and if it cannot be resolved by the Parties within thirty (30) days after written notice of the dispute to the other Party, the Parties shall submit the dispute to mediation by a mutually acceptable mediator, in a mutually convenient location in the same state as the Generation Facility location. The Parties agree to participate in good faith in the mediation for a period of 90 days. If the parties are not successful in resolving their disputes through mediation, then the Parties may refer the dispute for resolution to the Public Utilities Commission of the state in which the Generation Facility is located, which shall maintain continuing jurisdiction over this process. The rules of that state's PUC shall govern the dispute resolution.

C) Company Generation Interconnection Coordinator

Each Company Operator shall designate a Generation Interconnection Coordinator(s) and this person or persons shall provide a single point of contact for an Applicant's questions on this Generation Interconnection process. The Company Operator may have several Generation Interconnection Coordinators assigned, due to the geographical size of the electrical service territory or the amount of interconnection applications. This Generation Interconnection Coordinator will typically not be able to directly answer or resolve all of the issues involved in the review and implementation of the interconnection process and standards, but shall be available to provide coordination assistance with the Applicant. The Applicant is encouraged to discuss with or attend a pre-scoping meeting with the Coordinator to discuss potential difficulties, alternatives, and system compatibility issues before filing an application to interconnect.

D) Engineering Studies

During the process of design of a Generation System interconnection between a Generation System and the Company, there are several studies that many need to be undertaken. On the Local EPS (Customers side of the interconnection), the addition of a Generation System may increase the fault current levels, even if the generation is never interconnected with the Company's system. The Interconnection Customer may need to conduct a fault current analysis of the Local EPS in conjunction with adding the Generation System. The addition of the Generation System may also affect the Company and special engineering studies may need to be undertaken looking at the Company with the Generation System included. Appendix D lists some of the issues that may need to receive further analysis for the Generation System interconnection.

While it is not a straightforward process to identify which engineering studies are required, we can use screening criteria to identify which Generation Systems may require further analysis. The following are the basic screening criteria to be used for this interconnection process:

1) Generation System total Nameplate Capacity does not exceed 5% of the radial circuit expected peak load. The peak load is the total expected load on the radial circuit when the other generators on that same radial circuit are not in operation.

2) The aggregate generation's total Nameplate Capacity, including all existing and proposed generation, does not exceed 25% of the radial circuit peak load and that total is less than the radial circuit's minimum load.

3) Generation System does not exceed 15% of the Annual Peak Load for the Line Section with which it will interconnect. A Line Section is defined as that section of the distribution system between two sectionalizing devices in the Company's distribution system.

4) Generation System does not contribute more than 10% to the distribution circuit's maximum fault current at the point of interconnection with the Company's primary distribution voltage.

5) The proposed Generation System total Nameplate Capacity, in aggregate with other generation on the distribution circuit, will not cause any distribution protective devices and equipment to exceed 85 percent of the short circuit interrupting capability.

6) If the proposed Generation System is to be interconnected on a single-phase shared secondary, the aggregate generation Nameplate Capacity on the shared secondary, including the proposed generation, does not exceed 20 kW.

7) Generation System will not be interconnected with a "networked" system.

E) Scoping Meeting

During Step 2 of this process, the Applicant or the Company Operator has the option to request a scoping meeting. The purpose of the scoping meeting shall be to discuss the Applicant's interconnection request and review the application filed. This scoping meeting is to be held so that each Party can gain a better understanding of the issues involved with the requested interconnection. The Company and Applicant shall bring to the meeting personnel, including system engineers, and other resources as may be reasonably required, to accomplish the purpose of the meeting. The Applicant shall not expect the Company to complete the preliminary review of the proposed Generation System at the scoping meeting. If a scoping meeting is requested, the Company shall schedule the scoping meeting within the 15 business day review period allowed for in Step 2. The Company shall then have an additional 5 days, after the completion of the scoping meeting to complete the formal response required in Step 2. The Application fee shall cover the Company's costs for this scoping meeting. There shall be no additional charges imposed by the Company for this initial scoping meeting.

F) Insurance

1) At a minimum, in connection with the Interconnection Customer's performance of its duties and obligations under the Interconnection Agreement, the Interconnection Customer shall maintain, during the term of the Agreement, general liability insurance, from a qualified insurance agency with a B+ or better rating by "Best" and with a combined single limit of not less than:

   a) Two million dollars ($2,000,000) for each occurrence if the Gross Nameplate Rating of the Generation System is greater then 250 kW.

   b) One million dollars ($1,000,000) for each occurrence if the Gross Nameplate Rating of the Generation System is between 20 kW and 250 kW.

   c) Three hundred thousand ($300,000) for each occurrence if the Gross Nameplate Rating of the Generation System is less than 20 kW.

   d) Such general liability insurance shall include coverage against claims for damages resulting from (i) bodily injury, including wrongful death; and (ii) property damage arising out of the Interconnection Customer's ownership and/or operation of the Generation System under this agreement.

2) The general liability insurance required shall, by endorsement to the policy or policies, (a) include the Company Operator as an additional insured; (b) contain a severability of interest clause or cross-liability clause; (c) provide that the Company Operator shall not by reason of its inclusion as an additional insured incur liability to the insurance carrier for the payment of premium for such insurance; and (d) provide for thirty (30) calendar days' written notice to the Company Operator prior to cancellation, termination, alteration, or material change of such insurance.

3) If the Generation System is connected to an account receiving residential service from the Company Operator and it total generating capacity is 20 kW or smaller, then the endorsements required in Section F.2 shall not apply.

4) The Interconnection Customer shall furnish the required insurance certificates and endorsements to the Company Operator prior to the initial operation of the Generation System. Thereafter, the Company Operator shall have the right to periodically inspect or obtain a copy of the original policy or policies of insurance

5) Evidence of the insurance required in Section F.1 shall state that coverage provided is primary and is not excess to or contributing with any insurance or self-insurance maintained by the Company Operator.

6) If the Interconnection Customer is self-insured with an established record of self-insurance, the Interconnection Customer may comply with the following in lieu of Section F.1 - F.5:

7) Interconnection Customer shall provide to the Company Operator, at least thirty (30) days prior to the date of initial operation, evidence of an acceptable plan to self-insure to a level of coverage equivalent to that required under Section F.1 - F.5.

8) If Interconnection Customer ceases to self-insure to the level required hereunder, or if the Interconnection Customer is unable to provide continuing evidence of it's ability to self-insure, the Interconnection Customer agrees to immediately obtain the coverage required under Section F.1 - F.5.

Failure of the Interconnection Customer or Company Operator to enforce the minimum levels of insurance does not relieve the Interconnection Customer from maintaining such levels of insurance or relieve the Interconnection Customer of any liability.

G) Pre-Certification

The most important part of the process for interconnecting generation with Local and Company's systems is safety. One of the key components of ensuring the safety of the public and employees is to ensure that the design and implementation of the elements connected to the electrical power system operate as required. To meet this goal, all of the electrical wiring in a business or residence, is required to be listed by a recognized testing and certification laboratory for its intended purpose. Typically, we see this as "UL" listed. Since Generation Systems have tended to be uniquely designed for each installation, they have been designed and approved by Professional Engineers. This process has been set up to be able to deal with these uniquely designed systems. As the number of Generation Systems installed increase, vendors are working towards creating equipment packages that can be type-tested in the factory and then will only require limited field-testing. This will allow us to move towards "plug and play" installations. For this reason, this interconnection process recognizes the efficiently of "pre-certification" of Generation System equipment packages that will help streamline the design and installation process.

An equipment package shall be considered certified for interconnected operation if it has been submitted by a manufacture to and tested and listed by a nationally recognized testing and certification laboratory (NRTL) for continuous utility interactive operation in compliance with the applicable codes and standards. Presently generation paralleling equipment that is listed by a nationally recognized testing laboratory as having met the applicable type-testing requirements of IEEE 1547.1, including UL 1741, shall be acceptable for interconnection. An "equipment package" shall include all interface components including switchgear, inverters, or other interface devices and may include an integrated generator or electric source. If the equipment package has been type-tested and listed as an integrated package which includes a generator or other electric source, it shall not require further design review, testing or additional equipment to meet the certification requirements for interconnection. If the equipment package includes only the interface components (switchgear, inverters, or other interface devices), then the Interconnection Customer shall show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and consistent with the testing and listing specified for the package. Provided the generator or electric source combined with the equipment package is consistent with the testing and listing performed by the nationally recognized testing and certification laboratory, no further design review, testing or additional equipment shall be required to meet the certification requirements of this interconnection procedure. A certified equipment package does not include equipment provided by the Company.

The use of Pre-Certified equipment does not automatically qualify the Interconnection Customer to be interconnected to the Company. An application will still need to be submitted and an interconnection review may still need to be performed, to determine the compatibility of the Generation System with the Company. Typically, small Generation facilities utilizing pre-certified equipment would not be required to provide additional protective equipment. For larger installations, some additional equipment is often required. These aspects are discussed further in the interconnection requirements document.

H) Confidential Information

Except as otherwise agreed, each Party shall hold in confidence and shall not disclose confidential information to any person (except employees, officers, representatives, and agents who agree to be bound by this section).

Confidential information shall be clearly marked as such on each page or otherwise affirmatively identified. If a court, government agency, or entity with the right, power, and authority to do so, requests or requires either Party, by subpoena, oral disposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirements(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of this Agreement. In the absence of a protective order or waiver, the Party shall disclose such confidential information which, in the opinion of its counsel, the party is legally compelled to disclose. Each Party will use reasonable efforts to obtain reliable assurance that confidential treatment will be accorded any confidential information so furnished.

I) Non-Warranty

Neither by inspection, if any, or non-rejection, nor in any other way, does the Company Operator give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances or devices owned, installed or maintained by the Applicant or leased by the Applicant from third parties, including without limitation the Generation System and any structures, equipment, wires, appliances or devices pertinent thereto.

J) Required Documents

The chart below lists the documents required for each type and size of Generation System proposed for interconnection. Find your type of Generation System interconnection, across the top, then follow the chart straight down, to determine what documents are required as part of the interconnection process.

<table>
<tr><th colspan="6">GENERATION INTERCONNECTION DOCUMENT SUMMARY</th></tr>
<tr><th rowspan="2">Open Transfer</th><th rowspan="2">Quick Closed & Quick Open Transfer</th><th rowspan="2">Soft Loading Transfer</th><th colspan="3">Extended Parallel Operation</th></tr>
<tr><th>QF facility <=20 kW</th><th>Without Sales</th><th>With Sales</th></tr>
<tr><td colspan="6">Interconnection Process (This document)</td></tr>
<tr><td></td><td colspan="5">Interconnection Requirements for Extended Paralleled Distribution Generation Systems</td></tr>
<tr><td></td><td colspan="5">Generation Interconnection Application (Appendix B)</td></tr>
<tr><td></td><td></td><td colspan="4">Engineering Data Submittal (Appendix C)</td></tr>
<tr><td></td><td></td><td></td><td colspan="3">Interconnection Agreement (Appendix E)</td></tr>
<tr><td></td><td></td><td></td><td></td><td colspan="2">MISO / FERC</td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td>PPA</td></tr>
</table>

<u>Interconnection Process</u> = "Interconnection Process for Distributed Generation Systems." (This document)

<u>Generation Interconnection Application</u> = The application form in Appendix B of this document.

<u>Engineering Data Submittal</u> = The Engineering Data Form/Agreement, which is attached as Appendix C of this document.

Interconnection Agreement = "Interconnection Agreement for the Interconnection of Extended Parallel Distributed Generation Systems with the Company", which is attached as Appendix E to this document.

MISO = Midwest Independent System Operator, www.midwestiso.org

FERC = Federal Energy Regulatory Commission, www.ferc.gov

PPA = Power Purchase Agreement.

Process for Interconnection

Step 1 Application (By Applicant)

Once a decision has been made by the Applicant that they would like to interconnect a Generation System with the Company, the Applicant shall supply the Company with the following information:

1) Completed Generation Interconnection Application (Appendix B), including;
   a) One-line diagram showing:
      i) Protective relaying.
      ii) Point of Common Coupling.
   b) Site plan of the proposed installation.
   c) Proposed schedule of the installation.
2) Payment of the application fee, according to the following sliding scale:

Generation Interconnection Application Fees

Interconnection Type	≤ 20 kW	>20 kW & ≤250 kW	>250 kW & ≤500 kW	> 500 kW & ≤1000 kW	>1000 kW
Open Transfer	$0	$0	$0	$100	$100
Quick Closed & Quick Open	$0	$100	$100	$250	$500
Soft Loading	$100	$250	$500	$500	$1000
Extended Parallel (Pre-Certified System)	$0	$250	$1000	$1000	$1500
Other Extended Parallel Systems	$100	$500	$1500	$1500	$1500

This application fee is to contribute to the Company Operator's labor costs for administration, review of the design concept, and preliminary engineering screening for the proposed Generation System interconnection.

For the Application Fees chart above:
The size (kW) of the Generation System is the total maximum Nameplate Capacity of the Generation System.

Step 2 Preliminary Review (By the Company)

Within 15 business days of receipt of all the information listed in Step 1, the Company's Generation Interconnection Coordinator shall respond to the Applicant with the information listed below. (If the information required in Step 1 is not complete, the Applicant will be notified, within 10 business days of what is missing and no further review will be completed until the missing information is submitted. The 15-day clock will restart with the new submittal)

As part of Step 2, the proposed Generation System will be screened to see if additional Engineering Studies are required. The base screening criteria is listed in the general information section of this document.

1) A single point of contact with the Company Operator for this project. (Generation Interconnection Coordinator)

2) Approval or rejection of the generation interconnection request.
   a) Rejection – The Company shall supply the technical reasons, with supporting information, for rejection of the interconnection Application.
   b) Approval - An approved Application is valid for 6 months from the date of the approval. The Company Generation Interconnection Coordinator may extend this time if requested by the Applicant.

3) If additional specialized engineering studies are required for the proposed interconnection, the following information will be provided to the Applicant. Typical Engineering Studies are outlined in Appendix D. The costs to the Applicant, for these studies will not exceed the values shown in the following table for pre-certified equipment.

Generation System Size	**Engineering Study Maximum Costs**
<20 kW	$0
20 kW – 100 kW	$500
100 kW – 250 kW	$1000
>250 kW or not pre-certified equipment	Actual costs

   a) General scope of the engineering studies required.
   b) Estimated cost of the engineering studies.
   c) Estimated duration of the engineering studies.
   d) Additional information required allowing the completion of the engineering studies.
   e) Study authorization agreement.

4) Comments on the schedule provided.

5) If the rules of MISO (Midwest Independent System Operator) require that this interconnection request be processed through the MISO process, the Generation Interconnection Coordinator will notify the Applicant that the generation system is not eligible for review through the State process.

Step 3 Go-No Go Decision for Engineering Studies (By Applicant)

In this step, the Applicant will decide whether or not to proceed with the required engineering studies for the proposed generation interconnection. If no specialized engineering studies are required by the Company Operator, the Company Operator and the Applicant will automatically skip this step.

If the Applicant decides NOT to proceed with the engineering studies, the Applicant shall notify the Company Generation Interconnection Coordinator so other generation interconnection requests in the queue are not adversely impacted. Should the Applicant decide to proceed, the Applicant shall provide the following to the Company Generation Interconnection Coordinator:

1) Payment required by the Company Operator for the specialized engineering studies.

2) Additional information requested by the Company Operator to allow completion of the engineering studies.

Step 4 Engineering Studies (By Company)

In this step, the Company Operator will be completing the specialized engineering studies for the proposed generation interconnection as outlined in Step 2. These studies should be completed in the time frame provided in Step 2, by the Company. It is expected that the Company Operator shall make all reasonable efforts to complete the Engineering Studies within the time frames shown below. If additional time is required to complete the engineering studies, the Generation Interconnection Coordinator shall notify the Applicant and provide the reasons for the time extension. Upon receipt of written notice to proceed, payment of applicable fee, and receipt of all engineering study information requested by the Company Operator in Step 2, the Company Operator shall initiate the engineering studies.

Generation System Size	Engineering Study Completion
<=20 kW	20 working days
>20 kW – 250 kW	30 working days
>250 kW – 1 MW	40 working days
> 1 MW	90 working days

Once it is known by the Company Operator that the actual costs for the engineering studies will exceed the estimated amount by more the 25%, then the Applicant shall be notified. The Company Operator shall then provide the reason(s) for the studies needing to exceed the original estimated amount and provide an updated estimate of the total cost for the engineering studies. The Applicant shall be given the option of either withdrawing the application, or paying the additional estimated amount to continue with the engineering studies.

Step 5 Study Results and Construction Estimates (By the Company)

Upon completion of the specialized engineering studies, or if none were necessary, the following information will be provided to the Applicant.

1) Results of the engineering studies, if needed.

2) Monitoring & control requirements for the proposed generation.

3) Special protection requirements for the Generation System interconnection.

4) Comments on the schedule proposed by the Applicant.

5) Interconnection Agreement (if applicable).

6) Cost estimate and payment schedule for required Company work, including, but not limited to;
   a) Labor costs related to the final design review.
   b) Labor & expense costs for attending meetings.
   c) Required Dedicated Facilities and other Company modification(s).
   d) Final acceptance testing costs.

Step 6 Final Go-No Go Decision (By Applicant)

In this step, the Applicant shall again have the opportunity to indicate whether they want to proceed with the proposed generation interconnection. If the decision is NOT to proceed, the Applicant will notify the Company Generation Interconnection Coordinator so that other generation interconnections in the queue are not adversely impacted. Should the Applicant decide to proceed, a more detailed design, if not already completed by the Company, must be done, and the following information is to be supplied to the Company Generation Interconnection Coordinator:

1) Applicable up-front payment required by the Company, per Payment Schedule provided in Step 5 (if applicable).

2) Signed Interconnection Agreement (if applicable).

3) Final proposed schedule incorporating the Company comments. The schedule of the project should include such milestones as foundations poured, equipment delivery dates, all conduit installed, cutover (energizing of the new switchgear/transfer switch), Company work, relays set and tested, preliminary vendor testing, final Company acceptance testing, and any other major milestones.

4) Detailed one-line diagram of the Generation System, including the generator, transfer switch/switchgear, service entrance, lockable and visible disconnect, metering, protection and metering CT's / VT's, protective relaying, and generator control system.

5) Detailed information on the proposed equipment including wiring diagrams, models, and types.

6) Proposed relay settings for all interconnection required relays.

7) Detailed site plan of the Generation System.

8) Drawing(s) showing the monitoring system (as required per table 5A and section 5 of the "Interconnection Requirements for Extended Paralleled Distribution Generation Systems"; including a drawing that shows the interface terminal block with the Company monitoring system.

9) Proposed testing schedule and initial procedure, including;
   a) Time of day (after-hours testing required?).
   b) Days required.
   c) Testing steps proposed.

Step 7 Final Design Review (By the Company)

Within 15 business days of receipt of the information required in Step 6, the Company Generation Interconnection Coordinator will provide the Applicant with an estimated time table for final review. If the information required in Step 6 is not complete, the Applicant will be notified, within 10 business days of what information is missing. No further review may be completed until the missing information is submitted. The 15-business day clock will restart with the new submittal. This final design review shall not take longer then 15 additional business days to complete, for a total of 30 business days.

During this step, the Company shall complete the review of the final Generation System design. If the final design has significant changes from the Generation System proposed on the original Application, which invalidate the engineering studies or the preliminary engineering screening, the Generation System Interconnection Application request may be rejected by the Company Operator and the Applicant may be requested to reapply with the revised design.

Upon completion of this step, the Generation Interconnection Coordinator shall supply the following information to the Applicant.

1) Requested modifications or corrections of the detailed drawings provided by the Applicant.

2) Approval of and agreement with the Project Schedule. (This may need to be interactively discussed between the Parties during this Step)

3) Initial testing procedure review comments. (Additional work on the testing process will occur during Step 8, once the actual equipment is identified)

Step 8 Order Equipment and Construction (By Both Parties)

The following activities shall be completed during this step. For larger installations, this step will involve much interaction between the Parties. It is typical for approval drawings to be supplied by the Applicant to the Company for review and comments. It is also typical for the Company to require review and approval of the drawings that cover the interconnection equipment and interconnection protection system. If the Company also requires remote control and/or monitoring, those drawings are also exchanged for review and comment.

By the Applicant's personnel:
1) Ordering of Generation System equipment.
2) Installing Generation System.
3) Submit approval drawings for interconnection equipment and protection systems, as required by the Company Operator.
4) Provide final relay settings to the Company Operator.
5) Submit Completed and signed Engineering Data Submittal form.

6) Submit proof of insurance as required by the Company tariff(s) or interconnection agreements.
7) Submit required electrical inspection forms to the Company Operator.
8) Inspecting and functional testing Generation System components.
9) Work with the Company personnel and equipment vendor(s) to finalize the installation testing procedure.

By the Company personnel:

1) Ordering any necessary Company equipment.
2) Installing and testing any required equipment.
   a) Monitoring facilities.
   b) Dedicated Equipment.
3) Assisting Applicant's personnel with interconnection installation coordination issues.
4) Providing review and input for testing procedures.

Step 9 Final Tests (By Company / Applicant)

Due to equipment lead times and construction, a significant amount of time may take place between the execution of Step 8 and Step 9. During this time, the final test steps are developed and the construction of the facilities is completed. For installations 20 kW and under using pre-certified interconnection equipment, this step is typically highly abbreviated.

Final acceptance testing will commence when all equipment has been installed, all contractor preliminary testing has been accomplished, and all Company preliminary testing of the monitoring and dedicated equipment is completed. One to three weeks prior to the start of the acceptance testing of the generation interconnection, the Applicant shall provide a report stating:

- Generation System meets all interconnection requirements;
- contractor preliminary testing has been completed;
- protective systems are functionally tested and ready;
- and provides a proposed date that the Generation System will be is ready to be energized and acceptance tested.

For non-type certified systems a Professional Electrical Engineer registered in the State is required to provide this formal report.

For smaller systems, scheduling of this testing may be more flexible as less testing time is required than for larger systems.

In many cases, this testing is done after hours to ensure no typical business-hour load is disturbed. If acceptance testing occurs after hours, the Company Operator's labor will be billed at overtime wages. During this testing, the Company Operator will typically require three different tests. These tests can differ depending on which type of communication/monitoring system(s) the Company Operator decides to install at the site.

For problems created by the Company or any Company equipment problems that arise during testing, the Company will fix the problem as soon as reasonably possible. If problems arise during testing which are caused by the Applicant or Applicant's vendor or any vendor supplied or installed equipment, the Company will leave the project until the problem is resolved. Having the testing resume will then be subject to Company personnel's time and availability.

Step 10 (By Company)

After all of the Company Operator's required acceptance testing has been accomplished and all requirements are met, the Company Operator shall provide written approval for normal operation of the Generation System interconnection within 3 business days of the successful completion of the acceptance tests.

Step 11 (By Applicant)

Within two (2) months of interconnection, the Applicant shall provide the Company with updated drawings and prints showing the Generation System as approved for normal operation by the Company Operator. The drawings shall include all changes that were made during the construction and the testing process.

Attachments:

Attached are several documents that may be required for the interconnection process. They are as follows:

Appendix A: Flow chart showing summary of the interconnection process.

Appendix B: Generation Interconnection Application Form.

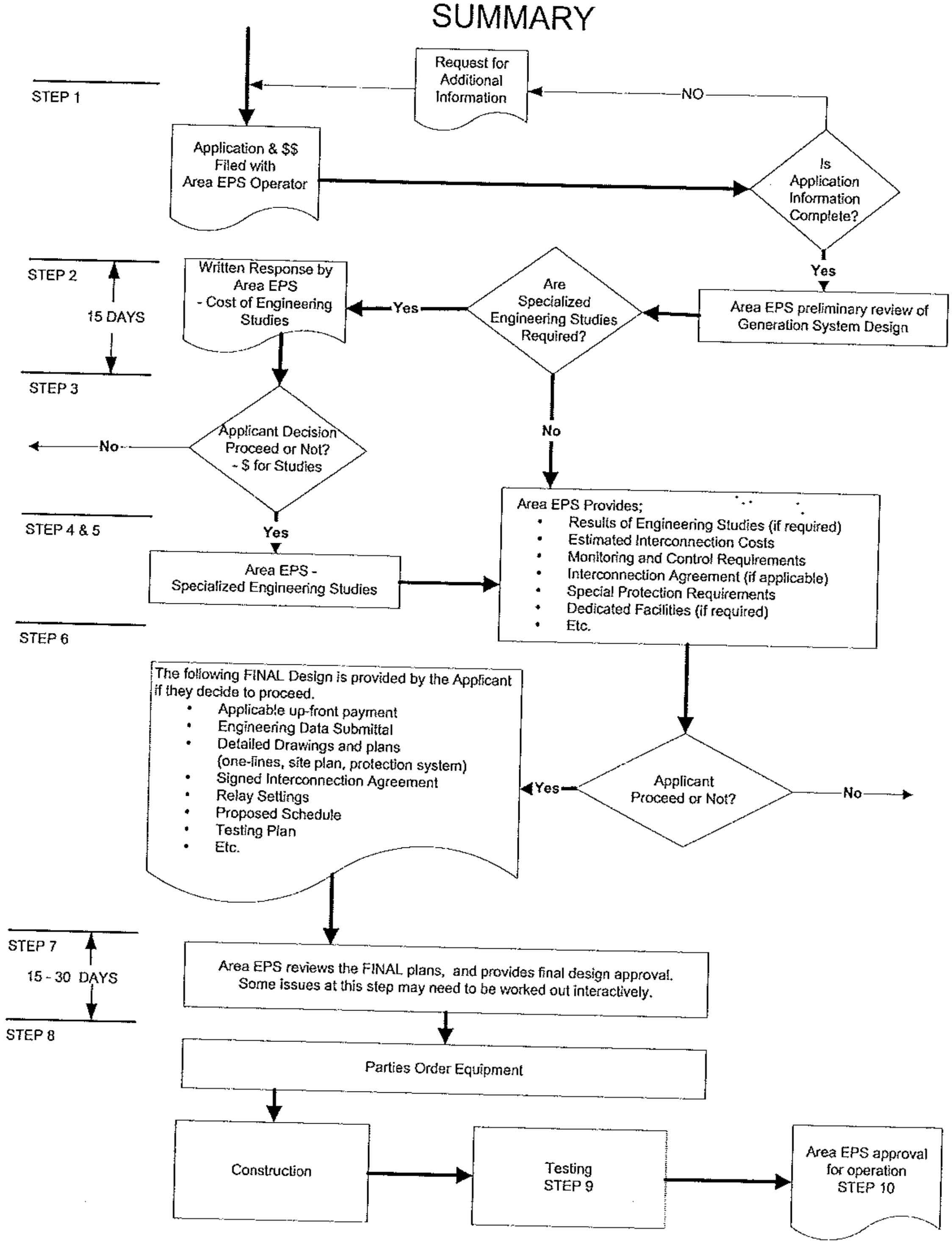
Appendix C: Engineering Data Submittal Form.

Appendix D: Engineering Studies: Brief description of the types of possible Engineering Studies that may be required for the review of the Generation System interconnection.

Appendix E: Interconnection Agreement for the Interconnection of Extended Paralleled Distributed Generation Systems with the Company.

APPENDIX A

DISTRIBUTED GENERATION INTERCONNECTION PROCESS SUMMARY



APPENDIX B

Application to Interconnect Form

WHO SHOULD FILE THIS APPLICATION: Anyone expressing interest to install generation that will interconnect with the Company. This application should be completed and returned to the Company Generation Interconnection Coordinator in order to begin processing the request.
INFORMATION: This application is used by the Company Operator to perform a preliminary interconnection review. The Applicant shall complete as much of the form as possible. The fields in BOLD are required to be completed to the best of the Applicant's ability. The Applicant will be contacted if additional information is required. The response may take up to 15 business days after receipt of all the required information.
COST: A payment to cover the application fee shall be included with this application. The application fee amount is outlined in the "Interconnection Process for Distributed Generation Systems".

OWNER/APPLICANT		
Company / Applicant's Name:		
Representative:	**Phone Number:**	**FAX Number:**
Title:		
Mailing Address:		
Email Address:		
LOCATION OF GENERATION SYSTEM INTERCONNECTION		
Street Address, legal description or GPS coordinates:		
PROJECT DESIGN / ENGINEERING (if applicable)		
Company:		
Representative:	Phone:	FAX Number:
Mailing Address:		
Email Address:		
ELECTRICAL CONTRACTOR (if applicable)		
Company:		
Representative:	Phone:	FAX Number:
Mailing Address:		
Email Address:		
GENERATOR		
Manufacturer:		Model:
Type (Synchronous Induction, Inverter, etc):		**Phases: 1 or 3**
Rated Output (Prime kW):	**(Standby kW):**	**Frequency:**
Rated Power Factor (%):	**Rated Voltage (Volts):**	Rated Current (Amperes):
Energy Source (gas, steam, hydro, wind, etc.)		
TYPE OF INTERCONNECTED OPERATION		
Interconnection / Transfer method: □ **Open** □ **Quick Open** □ **Closed** □ **Soft Loading** □ **Inverter**		
Proposed use of generation: (Check all that may apply) □ **Peak Reduction** □ **Standby** □ **Energy Sales** □ **Cover Load**	**Duration Parallel:** □ **None** □ **Limited** □ **Continuous**	

Pre-Certified System: Yes / No (Circle one)	**Exporting Energy Yes / No (Circle one)**

ESTIMATED LOAD INFORMATION

The following information will be used to help properly design the interconnection. This Information is not intended as a commitment or contract for billing purposes.

Minimum anticipated load (generation not operating):	**kW:**	**kVA:**
Maximum anticipated load (generation not operating):	**kW:**	**kVA:**

ESTIMATED START/COMPLETION DATES

Construction start date:	**Completion (operational) date:**

DESCRIPTION OF PROPOSED INSTALLATION AND OPERATION

Attach a single line diagram showing the switchgear, transformers, and generation facilities. Give a general description of the manner of operation of the generation (cogeneration, closed-transition peak shaving, open-transition peak shaving, emergency power, etc.). Also, does the Applicant intend to sell power and energy or ancillary services and/or wheel power over Company facilities? If there is intent to sell power and energy, also define the target market?

SIGN-OFF AREA:

With this Application, we are requesting the Company Operator to review the proposed Generation System Interconnection. We request that the Company identifies the additional equipment and costs involved with the interconnection of this system and to provide a budgetary estimate of those costs. We understand that the estimated costs supplied by the Company Operator will be estimated using the information provided. We also agree that we will supply, as requested, additional information to allow the Company Operator to better review this proposed Generation System interconnection. We have read the "Interconnection Requirements for Extended Paralleled Distribution Generation Systems" and will design the Generation System and interconnection to meet those requirements.

Applicant Name (print):

Applicant Signature: **Date:**

SEND THIS COMPLETED & SIGNED APPLICATION AND ATTACHMENTS TO THE COMPANY GENERATION INTERCONNECTION COORDINATOR

APPENDIX C

Engineering Data Submittal Form

WHO SHOULD FILE THIS SUBMITTAL: Anyone in the final stages of interconnecting a Generation System with the Company. This submittal shall be completed and provided to the Company Generation Interconnection Coordinator during the design of the Generation System as established in the "Interconnection Process for Distributed Generation Systems".

INFORMATION: This submittal is used to document the interconnected Generation System. The Applicant shall complete as much of the form as applicable. The Applicant will be contacted if additional information is required.

OWNER / APPLICANT		
Company / Applicant:		
Representative:	Phone Number:	FAX Number:
Title:		
Mailing Address:		
Email Address:		

PROPOSED LOCATION OF GENERATION SYSTEM INTERCONNECTION
Street Address, Legal Description or GPS coordinates:

PROJECT DESIGN / ENGINEERING (if applicable)		
Company:		
Representative:	Phone:	FAX Number:
Mailing Address:		
Email Address:		

ELECTRICAL CONTRACTOR (if applicable)		
Company:		
Representative:	Phone:	FAX Number:
Mailing Address:		
Email Address:		

TYPE OF INTERCONNECTED OPERATION	
Interconnection / Transfer method: □ Open □ Quick Open □ Closed □ Soft Loading □ Inverter	
Proposed use of generation: (Check all that may apply) □ Peak Reduction □ Standby □ Energy Sales □ Cover Load	Duration Parallel: □ None □ Limited □ Continuous
Pre-Certified System: Yes / No (Circle one)	Exporting Energy Yes / No (Circle one)

GENERATION SYSTEM OPERATION / MAINTENANCE CONTACT INFORMATION		
Maintenance Provider:	Phone #:	Pager #:
Operator Name:	Phone #:	Pager #:
Person to Contact before remote starting of units		
Contact Name:	Phone #:	Pager #:
	24 hr Phone #:	

GENERATION SYSTEM OPERATING INFORMATION	
Fuel Capacity (gals):	Full Fuel Run-time (hrs):
Engine Cool Down Duration (Minutes):	Start time Delay on Load Shed signal:
Start Time Delay on Outage (Seconds):	

ESTIMATED LOAD		
The following information will be used to help properly design the interconnection. This Information is not intended as a commitment or contract for billing purposes.		
Minimum anticipated load (generation not operating):	kW:	kVA:
Maximum anticipated load (generation not operating):	kW:	kVA:

REQUESTED CONSTRUCTION START/COMPLETION DATES	
Design Completion:	
Construction Start Date:	
Footings in place:	
Primary Wiring Completion:	
Control Wiring Completion:	
Start Acceptance Testing:	
Generation operational (In-service):	

(Complete all applicable items, copy these pages as required for additional generators)

SYNCHRONOUS GENERATOR (if applicable)

Unit Number:	Total number of units with listed specifications on site:		
Manufacturer:	Type:	Phases: 1 or 3	
Serial Number (each)	Date of manufacture:	Speed (RPM):	Freq. (Hz);
Rated Output (each unit) kW Standby:	kW Prime:	kVA:	
Rated Power Factor (%):	Rated Voltage (Volts):	Rated Current (Amperes):	
Field Voltage (Volts):	Field Current (Amperes):	Motoring Power (kW):	
Synchronous Reactance (X_d):	% on	kVA base	
Transient Reactance (X'_d):	% on	kVA base	
Subtransient Reactance (X''_d):	% on	kVA base	
Negative Sequence Reactance (X_s):	% on	kVA base	
Zero Sequence Reactance (X_o):	% on	kVA base	
Neutral Grounding Resistor (if applicable):			
I^2t or K (heating time constant):			
Exciter data:			
Governor data:			
Additional Information:			

INDUCTION GENERATOR (if applicable)

Rotor Resistance (R_r):	Ohms	Stator Resistance (R_s):	Ohms
Rotor Reactance (X_r):	Ohms	Stator Reactance (X_s):	Ohms
Magnetizing Reactance (X_m):	Ohms	Short Circuit Reactance (X_d''):	Ohms
Design Letter:		Frame Size:	
Exciting Current:		Temp Rise (deg C°):	
Rated Output (kW):			
Reactive Power Required:	kVArs (no Load)		kVArs (full load)

If this is a wound-rotor machine, describe any external equipment to be connected (resistor, rheostat, power converter, etc.) to rotor circuit, and circuit configuration. Describe ability, if any, to adjust generator reactive output to provide power system voltage regulation.

Additional Information:

PRIME MOVER (Complete all applicable items)

Unit Number:	Type:
Manufacturer:	
Serial Number:	Date of Manufacture:

H.P. Rated:	H.P. Max:	Inertia Constant:	lb.-ft.^{2}
Energy Source (hydro, steam, wind, wind etc.):			

INTERCONNECTION (STEP-UP) TRANSFORMER (If applicable)		
Manufacturer:	kVA:	
Date of Manufacture:	Serial Number:	
High Voltage: kV	Connection: delta wye	Neutral solidly grounded?
Low Voltage: kV	Connection: delta wye	Neutral solidly grounded?
Transformer Impedance (Z):	% on	kVA base
Transformer Resistance (R):	% on	kVA base
Transformer Reactance (X):	% on	kVA base
Neutral Grounding Resistor (if applicable)		

TRANSFER SWITCH (If applicable)	
Model Number:	Type:
Manufacturer:	Rating(amps):

INVERTER (If applicable)		
Manufacturer:	Model:	
Rated Power Factor (%):	Rated Voltage (Volts):	Rated Current (Amperes):
Inverter Type (ferroresonant, step, pulse-width modulation, etc.):		
Type of Commutation: forced line	Minimum Short Circuit Ratio required:	
Minimum voltage for successful commutation:		
Current Harmonic Distortion	Maximum Individual Harmonic (%): Maximum Total Harmonic Distortion (%):	
Voltage Harmonic Distortion	Maximum Individual Harmonic (%): Maximum Total Harmonic Distortion (%):	
Describe capability, if any, to adjust reactive output to provide voltage regulation:		
NOTE: Attach all available calculations, test reports, and oscillographic prints showing inverter output voltage and current waveforms.		

POWER CIRCUIT BREAKER (if applicable)					
Manufacturer:	Model:				
Rated Voltage (kilovolts):	Rated Ampacity (Amperes):				
Interrupting Rating (Amperes):	BIL Rating:				
Interrupting Medium (vacuum, oil, gas, etc.)	Insulating Medium (vacuum, oil, gas, etc.)				
Control Voltage (Closing):	(Volts)	AC	DC		
Control Voltage (Tripping):	(Volts)	AC	DC	Battery	Charged Capacitor
Close Energy (circle one):	Spring	Motor	Hydraulic	Pneumatic	Other
Trip Energy (circle one):	Spring	Motor	Hydraulic	Pneumatic	Other
Bushing Current Transformers (Max. ratio):	Relay Accuracy Class:				
CT'S Multi Ratio? (circle one);	No / Yes:	(Available taps):			

MISCELLANEOUS (Use this area and any additional sheets for applicable notes and comments)

SIGN OFF AREA

This Engineering Data Submittal documents the equipment and design of the Generation System. We agree to supply the Company Operator with an updated Engineering Data Submittal any time significant changes are made in the equipment used or the design of the proposed Generation System. The Applicant agrees to design, operate, and maintain the Generation System within the requirements set forth by the "Interconnection Requirements for Extended Paralleled Distribution Generation Systems".

Applicant Name (print):

Applicant Signature: **Date:**

SEND THIS COMPLETED & SIGNED ENGINEERING DATA SUBMITTAL AND ANY ATTACHMENTS TO THE COMPANY GENERATION INTERCONNECTION COORDINATOR

APPENDIX D

Engineering Studies

For the engineering studies, there are two main parts of the study: 1. Does the distributed generator cause a problem? and 2. What would it cost to make a change to handle the problem? The first question is relatively straightforward to determine as the Company Engineer reviews the proposed installation. The second question typically has multiple alternatives and can turn into an iterative process. This iterative process can become quite large for more complex generation installations. For the Engineer, there is no "cook book" solution that can be applied.

For some of the large generation installations and/or the more complex interconnections, the Company Operator may suggest dividing the engineering studies into the two parts: 1. identify the scope of the problems, and 2. attempt to identify solutions to resolve the problems. By splitting the engineering studies into two steps, it will allow the Applicant to see the problems identified and to provide the Applicant the ability to remove the request for interconnection if the problems are too large and expensive to resolve. This would then save the additional costs to the Applicant for the more expensive engineering studies to identity ways to resolve the problem(s).

This appendix provides an overview of some of the main issues that are looked at during the engineering study process. Every interconnection has its unique issues, such as relative strength of the distribution system, ratio of the generation size to the existing area loads, etc. Thus, many of the generation interconnections will require further review of one or several of the issues listed.

- Short circuit analysis – the system is studied to make sure that the addition of the generation will not over stress any of the Company equipment and that equipment will still be able to clear during a fault. It is expected that the Applicant will complete their own short circuit analysis on their equipment to ensure that the addition of the generation system does not overstress the Applicant's electrical equipment.

- Power Flow and Voltage Drop
  - Reviews potential islanding of the generation.
  - Will Company Equipment be overloaded?
    - Under normal operation?
    - Under contingent operation?
    - With backfeeds?

- Flicker Analysis –
  - Will the operation of the generation cause voltage swings?
    - When it loads up?
    - When it off-loads?
  - How will the generation interact with Company voltage regulation?
  - Will Company capacitor switching affect the generation while on-line?

- Protection Coordination
  - Reclosing issues – this is where the reclosing for the distribution system and transmission system are looked at to see if the Generation System protection can be set up to ensure that it will clear from the distribution system before the feeder is reenergized.
    - Is voltage supervision of reclosing needed?
  - Is transfer-trip required?
  - Do we need to modify the existing protection systems? Existing settings?
  - At which points do we need "out of sync" protection?
  - Is the proposed interconnection protection system sufficient to sense a problem on the Company's system?
  - Are there protection problems created by the step-up transformer?

- Grounding Reviews
  - Does the proposed grounding system for the Generation System meet the requirements of the NESC? "National Electrical Safety Code" published by the Institute of Electrical and Electronics Engineers (IEEE)

- System Operation Impact.
  - Are special operating procedures needed with the addition of the generation?

- Reclosing and out of sync operation of facilities?
- What limitations need to be placed on the operation of the generation?
- Operational var requirements?

APPENDIX E

Interconnection Agreement for the Interconnection of Extended Parallel Distributed Generation Systems

This Generating System Interconnection Agreement is entered into by and between the Area Electrical Power System Operator (Company Operator) "________________________" and the Interconnection Customer "______________________________". The Interconnection Customer and the Company are sometimes also referred to in this Agreement jointly as "Parties" or individually as "Party".

In consideration of the mutual promises and obligations stated in this Agreement and its attachments, the Parties agree as follows:

I. SCOPE AND PURPOSE

A) Establishment of Point of Common Coupling: This Agreement is intended to provide for the Interconnection Customer to interconnect and operate a Generation System, with a total Nameplate Capacity of 10 MWs or less, in parallel with the Company at the location identified in Exhibit C and shown in the Exhibit A one-line diagram.

B) This Agreement governs the facilities required to and contains the terms and condition under which the Interconnection Customer may interconnect the Generation System to the Company. This Agreement does not authorize the Interconnection Customer to export power or constitute an agreement to purchased or wheel the Interconnection Customer's power. Other services that the Interconnection Customer may require from the Company, or others, may be covered under separate agreements.

C) To facilitate the operation of the Generation System, this agreement also allows for the occasional and inadvertent export of energy to the Company. The amount, metering, billing, and accounting of such inadvertent energy exporting shall be governed by Exhibit D (Operating Agreement). This Agreement does not constitute an agreement by the Company Operator to purchase or pay for any energy, inadvertently or intentionally exported, unless expressly noted in Exhibit D or under a separately executed power purchase agreement (PPA).

D) This agreement does not constitute a request for, nor the provision of, any transmission delivery service or any local distribution delivery service.

E) The Technical Requirements for interconnection are covered in a separate Technical Requirements document known as the "Interconnection Requirements for Extended Paralleled Distribution Generation Systems", a copy of which as been made available to the Interconnection Customer and incorporated and made part of this Agreement by this reference.

II. DEFINITIONS

A) "Area EPS" - the area electric power system that is also referred to as the Company electric distribution system in this document.

B) "Company" - an electric power system (EPS) that serves the Local EPS. Note: Typically, the Company has primary access to public rights-of-way, priority crossing of property boundaries, etc.

C) "Company Operator" - the entity that operates the Company's electric distribution system.

D) "Commission" – The public utilities commission of the State wherein the Generation Facility is located.

E) "Dedicated Facilities" - the equipment that is installed due to the interconnection of the Generation System and not required to serve other Company customers.

F) "EPS" - (Electric Power System) facilities that deliver electric power to a load. Note: This may include generation units.

G) "Extended Parallel" - means the Generation System is designed to remain connected with the Company for an extended period of time.

H) "Generation" - any device producing electrical energy; i.e., rotating generators driven by wind, steam turbines, internal combustion engines, hydraulic turbines, solar, fuel cells, etc.; or any other electric producing device, including energy storage technologies.

I) "Generation Interconnection Coordinator" - the person or persons designated by the Company Operator to provide a single point of coordination with the Applicant for the generation interconnection process.

J) "Generation System" - the interconnected generator(s), controls, relays, switches, breakers, transformers, inverters and associated wiring and cables up to the Point of Common Coupling.

K) "Interconnection Customer" - the party or parties who will own/operate the Generation System and are responsible for meeting the requirements of the agreements and Technical Requirements. This could be the Generation System applicant, installer, owner, designer, or operator.

L) "Local EPS" - an electric power system (EPS) contained entirely within a single premises or group of premises.

M) "Nameplate Capacity" - the total nameplate capacity rating of all the Generation included in the Generation System. For this definition, the "standby" and/or maximum rated kW capacity on the nameplate shall be used.

N) "Open Transfer" - a method of transferring the local loads from the Company to the generator such that the generator and the Company are never connected together.

O) "Point of Common Coupling" - the point where the Local EPS is connected to the Company's distribution system.

P) "Point of Delivery" - the point where the energy changes possession from one party to the other. Typically this will be where the metering is installed but it is not required that the Point of Delivery is the same as where the energy is metered.

Q) "Quick Closed" - a method of generation transfer that parallels for less than 100 msec with the Company and has utility grade timers that limit the parallel duration to less than 100 msec with the Company.

R) "Quick Open" - a method of generation transfer that does not parallel with the Company and has a brief open interval, typically about 100 msec.

S) "Soft Loading Transfer": - a method of generation load transfer that parallels for typically less than 2 minutes to gradually transfer load between the generator and the Company.

T) "State" - the state wherein the interconnected generator is located.

U) "Technical Requirements" - "Requirements for Interconnection of Distributed Generation".

III. DESCRIPTION OF INTERCONNECTION CUSTOMER'S GENERATION SYSTEM

A) A description of the Generation System, including a single-line diagram showing the general arrangement of how the Interconnection Customer's Generation System is interconnected with the Company's distribution system, is attached to and made part of this Agreement as Exhibit A. The single-line diagram shows the following:

1) Point of Delivery (if applicable)

2) Point of Common Coupling

3) Location of Meter(s)

4) Ownership of the equipment.

5) Generation System total Nameplate Capacity ________ kW

6) Scheduled operational (on-line) date for the Generation System.

IV. RESPONSIBILITIES OF THE PARTIES

A) The Parties shall perform all obligations of this Agreement in accordance with all applicable laws and regulations, operating requirements, and good utility practices.

B) Interconnection Customer shall construct, operate, and maintain the Generation System in accordance with the applicable manufacture's recommend maintenance schedule, the Technical Requirements, and in accordance with this Agreement.

C) The Company Operator shall carry out the construction of the Dedicated Facilities in a good and workmanlike manner and in accordance with standard design and engineering practices.

V. CONSTRUCTION

The Parties agree to cause their facilities or systems to be constructed in accordance with the laws of the State and to meet or exceed applicable codes and standards provided by the NESC (National Electrical Safety Code), ANSI (American National Standards Institute), IEEE (Institute of Electrical and Electronic Engineers), NEC (National Electrical Code), UL (Underwriter's Laboratory), Technical Requirements, local building codes, and other applicable ordinances in effect at the time of the installation of the Generation System.

A) Charges and Payments

The Interconnection Customer is responsible for the actual costs to interconnect the Generation System with the Company, including, but not limited to, any Dedicated Facilities attributable to the addition of the Generation System, Company labor for installation coordination, installation testing, and engineering review of the Generation System and interconnection design. Estimates of these costs are outlined in Exhibit B. While estimates, for budgeting purposes, have been provided in Exhibit B, the actual costs are still the responsibility of the Interconnection Customer even if they exceed the estimated amount(s). All costs, for which the Interconnection Customer is responsible must be reasonable under the circumstances of the design and construction.

1) Dedicated Facilities

a) During the term of this Agreement, the Company Operator shall design, construct, and install the Dedicated Facilities outlined in Exhibit B. The Interconnection Customer shall be responsible for paying the actual costs of the Dedicated Facilities attributable to the addition of the Generation System.

b) Once installed, the Dedicated Facilities shall be owned and operated by the Company and all costs associated with the operating and maintenance of the Dedicated Facilities, after the Generation System is operational, shall be the responsibility of the Company Operator unless otherwise agreed.

c) By executing this Agreement, the Interconnection Customer grants permission for the Company Operator to begin construction and to procure the necessary facilities and equipment to complete the installation of the Dedicated Facilities as outlined in Exhibit B. If for any reason, the Generation System project is canceled or modified, so that any or all of the Dedicated Facilities are not required, the Interconnection Customer shall be responsible for all costs incurred by the Company, including, but not limited to, the additional costs to remove and/or complete the installation of the Dedicated Facilities. The Interconnection Customer may, for any reason, cancel the Generation System project so that any or all of the Dedicated Facilities are not required to be installed. The Interconnection Customer shall provide written notice to the

Company Operator of cancellation. Upon receipt of a cancellation notice, the Company Operator shall take reasonable steps to minimize additional costs to the Interconnection Customer, where reasonably possible.

2) Payments

a) The Interconnection Customer shall provide reasonable adequate assurances of credit including a letter of credit or personal guaranty of payment and performance from a creditworthy entity acceptable under the Company Operator's credit policy and procedures for the unpaid balance of the estimated amount shown in Exhibit B.

b) The payment for the costs outlined in Exhibit B, shall be as follows;

i. 1/3 of estimated costs, outlined in Exhibit B, shall be due upon execution of this agreement.

ii. 1/3 of estimated costs, outlined in Exhibit B, shall be due before initial energization of the Generation System with the Company.

iii. Remainder of actual costs incurred by the Company shall be due within 30 days from the date the bill is mailed by the Company after project completion.

VI. DOCUMENTS INCLUDED WITH THIS AGREEMENT.

A) This agreement includes the following exhibits, which are specifically incorporated herein and made part of this Agreement by this reference: *(if any of these Exhibits are deemed not applicable for this Generation System installation, they may be omitted from the final Agreement by the Company Operator.)*

1) Exhibit A – Description of Generation System and single-line diagram. This diagram shows all major equipment, including visual isolation equipment, Point of Common Coupling, Point of Delivery for Generation Systems that intentionally export, ownership of equipment, and the location of metering.

2) Exhibit B – Estimated installation and testing costs payable by the Interconnection Customer. Included in this listing shall be the description and estimated costs for the required Dedicated Facilities being installed by the Company Operator for the interconnection of the Generation System and a description and estimate for the final acceptance testing work to be done by the Company Operator.

3) Exhibit C – Engineering Data Submittal – A standard form that provides the engineering and operating information about the Generation System.

4) Exhibit D – Operating Agreement – This provides specific operating information and requirements for this Generation System interconnection. This Exhibit has a separate signature section and may be modified, in writing, from time to time with the agreement of both parties.

5) Exhibit E – Maintenance Agreement – This provides specific maintenance requirements for this Generation System interconnection. This Exhibit has a separate signature section and may be modified, in writing, from time to time with the agreement of both parties.

VII. TERMS AND TERMINATION

A) This Agreement shall become effective as of the date when both the Interconnection Customer and the Company Operator have both signed this Agreement. The Agreement shall continue in full force and effect until the earliest date that one of the following events occurs:

1) The Parties agree in writing to terminate the Agreement; or

2) The Interconnection Customer may terminate this agreement at any time, by written notice to the Company Operator, prior to the completion of the final acceptance testing of the Generation System by the Company Operator. Once the Generation System is operational, then VII.A.3 applies. Upon receipt of a cancellation notice, the Company Operator shall take reasonable steps to minimize additional costs to the Interconnection Customer, where reasonably possible; or

3) Once the Generation System is operational, the Interconnection Customer may terminate this agreement after 30 days written notice to the Company Operator, unless otherwise agreed to within the Exhibit D, Operating Agreement; or

4) The Company Operator may terminate this agreement after 30 days written notice to the Interconnection Customer if:

a) The Interconnection Customer fails to interconnect and operate the Generation System per the terms of this Agreement; or

b) The Interconnection Customer fails to take all corrective actions specified in the Company's written notice that the Generation System is out of compliance with the terms of this Agreement, within the time frame set forth in such notice; or

c) If the Interconnection Customer fails to complete the Company Operator's final acceptance testing of the generation system within 24 months of the date proposed under section III.A.5.

B) Upon termination of this Agreement, the Generation System shall be disconnected from the Company. The termination of this Agreement shall not relieve either Party of its liabilities and obligations, owed or continuing, at the time of the termination.

VIII. OPERATIONAL ISSUES

Each Party will, at its own cost and expense, operate, maintain, repair, and inspect and shall be fully responsible for the facilities that it now or hereafter may own, unless otherwise specified.

A) Technical Standards: The Generation System shall be installed and operated by the Interconnection Customer consistent with the requirements of this Agreement; the Technical Requirements; the applicable requirements located in the National Electrical Code (NEC); the applicable standards published by the American National Standards Institute (ANSI) and the Institute of Electrical and Electronic Engineers (IEEE); and local building and other applicable ordinances in effect at the time of the installation of the Generation System.

B) Right of Access: At all times, the Company Operator's personnel shall have access to the disconnect switch of the Generation System for any reasonable purpose in connection with the performance of the obligations imposed on it by this Agreement to meet its obligation to operate the Company safely and to provide service to its customers. If necessary for the purposes of this Agreement, the Interconnection Customer shall allow the Company Operator access to the Company's equipment and facilities located on the premises.

C) Electric Service Supplied: The Company will supply the electrical requirements of the Local EPS that are not supplied by the Generation System. Such electric service shall be supplied to the Interconnection Customer's Local EPS under the rate schedules applicable to the Customer's class of service as revised from time to time by the Company.

D) Operation and Maintenance: The Generation System shall be operated and maintained by the Interconnection Customer in accordance with the Technical Standards and any additional requirements of Exhibit D and Exhibit E, attached to this document, as amended in writing from time to time.

E) Cooperation and Coordination: Both the Company Operator and the Interconnection Customer shall communicate and coordinate their operations so that the normal operation of the Company does not unduly effect or interfere with the normal operation of the Generation System and the Generation System does not unduly effect or interfere with the normal operation of the Company. Under abnormal operations of either the Generation System or the Company system, the responsible Party shall provide reasonably timely communication to the other Party to allow mitigation of any potentially negative effects of the abnormal operation of their system.

F) Disconnection of Unit: The Company Operator may disconnect the Generation System, as necessary, for termination of this Agreement; non-compliance with this Agreement; system emergency, imminent danger to the public or Company personnel; or routine maintenance, repairs and modifications to the Company. When reasonably possible, the Company Operator shall provide prior notice to the Interconnection Customer explaining the reason for the disconnection. If prior notice is not reasonably possible, the Company Operator shall, after the fact, provide information to the Interconnection Customer as to why the disconnection was required. It is agreed that the Company Operator shall have no liability for any loss of sales or other damages, including all consequential damages for the loss of business opportunity, profits, or other losses, regardless of whether such damages were foreseeable, for the disconnection of the Generation System per this Agreement. The Company Operator shall expend reasonable effort to reconnect the Generation System in a timely manner and to work towards mitigating damages and losses to the Interconnection Customer where reasonably possible.

G) Modifications to the Generation System – When reasonably possible, the Interconnection Customer shall notify the Company Operator, in writing, of plans for any modifications to the Generation System interconnection equipment, including all information needed by the Company Operator as part of the review described in this paragraph, at least twenty (20) business days prior to undertaking such modification(s). Modifications to any of the interconnection equipment, including all interconnection required protective systems, the generation control systems, the transfer switches/breakers, interconnection protection VT's & CT's, and Generation System capacity, shall be included in the notification to the Company Operator. When reasonably possible, the Interconnection Customer agrees not to commence installation of any modifications to the Generating System until the Company Operator has approved the modification, in writing, which approval shall not be unreasonably withheld. The Company Operator shall have a minimum of five (5) business days to review and respond to the planned modification. The Company Operator shall not take longer than a maximum of ten (10) business days to review and respond to the modification after the receipt of the information required to review the modifications. When it is not reasonably possible for the Interconnection Customer to provide prior written notice, the Interconnection Customer shall provide written notice to the Company Operator as soon as reasonably possible after the completion of the modification(s).

H) Permits and Approvals: The Interconnection Customer shall obtain all environmental and other permits lawfully required by governmental authorities before the construction of the Generation System. The Interconnection Customer shall also maintain these applicable permits and compliance with these permits during the term of this Agreement.

IX. LIMITATION OF LIABILITY

A) Each Party shall at all times indemnify, defend, and save the other Party harmless from any and all damages, losses, claims, including claims and actions relating to injury or death of any person or damage to property, costs and expenses, reasonable attorneys' fees and court costs, arising out of or resulting from the Party's performance of its obligations under this agreement, except to the extent that such damages, losses, or claims were caused by the negligence or intentional acts of the other Party.

B) Each Party's liability to the other Party for failure to perform its obligations under this Agreement shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any punitive, incidental, indirect, special, or consequential damages of any kind whatsoever, including for loss of business opportunity or profits, regardless of whether such damages were foreseen.

C) Notwithstanding any other provision in this Agreement, with respect to Company Operator's provision of electric service to any customer, including the Interconnection Customer, the Company Operator's liability to such customer shall be limited as set forth in the Company Operator's tariffs and terms and conditions for electric service, and shall not be affected by the terms of this Agreement.

X. DISPUTE RESOLUTION

A) Each Party agrees to attempt to resolve all disputes arising hereunder promptly, equitably, and in a good faith manner.

B) In the event a dispute arises under this Agreement, and if it cannot be resolved by the Parties within thirty (30) days after written notice of the dispute to the other Party, the Parties agree to submit the dispute to mediation by a mutually acceptable mediator, in a mutually convenient location in the State. The Parties agree to participate in good faith in the mediation for a period of 90 days. If the parties are not successful in resolving their disputes through mediation, then the Parties may refer the dispute for resolution to the Commission, which shall maintain continuing jurisdiction over this Agreement.

XI. INSURANCE

A) At a minimum, in connection with the Interconnection Customer's performance of its duties and obligations under this Agreement, the Interconnection Customer shall maintain during the term of the Agreement, general liability insurance from a qualified insurance agency with a B+ or better rating by "Best" and with a combined single limit of not less than:

1) Two million dollars ($2,000,000) for each occurrence if the Gross Nameplate Rating of the Generation System is greater then 250 kW.

2) One million dollars ($1,000,000) for each occurrence if the Gross Nameplate Rating of the Generation System is between 20 kW and 250 kW.

3) Three hundred thousand ($300,000) for each occurrence if the Gross Nameplate Rating of the Generation System is less than 20 kW.

4) Such general liability insurance shall include coverage against claims for damages resulting from (i) bodily injury, including wrongful death; and (ii) property damage arising out of the Interconnection Customer's ownership and/or operating of the Generation System under this agreement.

B) The general liability insurance required shall, by endorsement to the policy or policies, (a) include the Company Operator as an additional insured; (b) contain a severability of interest clause or cross-liability clause; (c) provide that the Company Operator shall not by reason of its inclusion as an additional insured incur liability to the insurance carrier for the payment of premium for such insurance; and (d) provide for thirty (30) calendar days' written notice to the Company Operator prior to cancellation, termination, alteration, or material change of such insurance.

C) If the Generation System is connected to an account receiving residential service from the Company Operator and its total generating capacity is 20 kW or smaller, then the endorsements required in Section XI.B shall not apply.

D) The Interconnection Customer shall furnish the required insurance certificates and endorsements to the Company Operator before the initial operation of the Generation System. Thereafter, the Company Operator shall have the right to periodically inspect or obtain a copy of the original policy or policies of insurance.

E) Evidence of the insurance required in Section XI.A. shall state that coverage provided is primary and is not excess to or contributing with any insurance or self-insurance maintained by the Company Operator.

F) If the Interconnection Customer is self-insured with an established record of self-insurance, the Interconnection Customer may comply with the following in lieu of Section XI.A – E:

1) Interconnection Customer shall provide to the Company Operator, at least thirty (30) days prior to the date of initial operation, evidence of an acceptable plan to self-insure to a level of coverage equivalent to that required under section XI.A - E.

2) If Interconnection Customer ceases to self-insure to the level required hereunder, or if the Interconnection Customer is unable to provide continuing evidence of it's ability to self-insure, the Interconnection Customer agrees to immediately obtain the coverage required under Section XI.A - E.

G) Failure of the Interconnection Customer or Company Operator to enforce the minimum levels of insurance does not relieve the Interconnection Customer from maintaining such levels of insurance or relieve the Interconnection Customer of any liability.

H) All insurance certificates, statements of self-insurance, endorsements, cancellations, terminations, alterations, and material changes of such insurance shall be issued and submitted to the following:

Company____________________

Attention____________________

Address____________________

____

XII. MISCELLANEOUS

A) FORCE MAJEURE

1) An event of Force Majeure means any act of God, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. An event of Force Majeure does not include an act of negligence or intentional wrongdoing.

2) Neither Party will be considered in default of any obligation hereunder if such Party is prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Agreement is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations hereunder.

B) NOTICES

1) Any written notice, demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given if delivered in person or sent by first class mail, postage prepaid, to the person specified below:

a) If to Company Operator

Company____________________

Attention____________________

Address____________________

____

b) If to Interconnection Customer

Customer____________________

Address____________________

____

2) A Party may change its address for notices at any time by providing the other Party written notice of the change, in accordance with this Section.

3) The Parties may also designate operating representatives to conduct the daily communications that may be necessary or convenient for the administration of this Agreement. Such designations, including names, addresses, and phone numbers may be communicated or revised by one Party's written notice to the other Party.

C) **ASSIGNMENT**

The Interconnection Customer shall not assign its rights nor delegate its duties under this Agreement without the Company Operator's written consent. Any assignment or delegation the Interconnection Customer makes without the Company Operator's written consent shall not be valid. The Company Operator shall not unreasonably withhold its consent to the Generating Entities assignment of this Agreement.

D) **NON-WAIVER**

None of the provisions of this Agreement shall be considered waived by a Party unless such waiver is given in writing. The failure of a Party to insist in any one or more instances upon strict performance of any of the provisions of this Agreement or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect.

E) **GOVERNING LAW AND INCLUSION OF COMPANY OPERATOR'S TARIFFS AND RULES.**

1) This Agreement shall be interpreted, governed, and construed under the laws of the State as if executed and to be performed wholly within the State without giving effect to choice of law provisions that might apply to the law of a different jurisdiction.

2) The interconnection and services provided under this Agreement shall at all times be subject to the terms and conditions set forth in the tariff schedules and rules applicable to the electric service provided by the Company Operator, which tariff schedules and rules are hereby incorporated into this Agreement by this reference.

3) Notwithstanding any other provisions of this Agreement, the Company Operator shall have the right to unilaterally file with the Commission, pursuant to the Commission's rules and regulations, an application for change in rates, charges, classification, service, tariff, or rule or any agreement relating thereto.

F) **AMENDMENT AND MODIFICATION**

This Agreement can only be amended or modified in writing and signed by both Parties.

G) **ENTIRE AGREEMENT**

This Agreement, including all attachments, exhibits, and appendices, constitutes the entire Agreement between the Parties with regard to the interconnection of the Generation System of the Parties at the Point(s) of Common Coupling expressly provided for in this Agreement and supersedes all prior agreements or understandings, whether verbal or written. It is expressly acknowledged that the Parties may have other agreements covering other services not expressly provided for herein, which agreements are unaffected by this Agreement. Each party also represents that in entering into this Agreement, it has not relied on the promise, inducement, representation, warranty, agreement, or other statement not set forth in this Agreement or in the incorporated attachments, exhibits, and appendices.

H) **CONFIDENTIAL INFORMATION**

Except as otherwise agreed or provided herein, each Party shall hold in confidence and shall not disclose confidential information to any person (except employees, officers, representatives, and agents who agree to be bound by this section). Confidential information shall be clearly marked as such on each page or otherwise affirmatively identified. If a court, government agency or entity with the right, power, and authority to do so requests or requires either Party by subpoena, oral disposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirements(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of this Agreement. In the absence of a protective order or waiver, the Party shall disclose such confidential information that, in the opinion of its counsel, the party is legally compelled to disclose. Each Party will use reasonable efforts to obtain reliable assurance that confidential treatment will be accorded any confidential information so furnished.

I) **NON-WARRANTY**

Neither by inspection, if any, or non-rejection, nor in any other way, does the Company Operator give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances, or devices owned, installed, or maintained by the Interconnection Customer or leased by the Interconnection Customer from third parties, including without limitation the Generation System and any structures, equipment, wires, appliances, or devices appurtenant thereto.

J) **NO PARTNERSHIP**

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation, or partnership liability upon either Party. Neither Party shall have any right, power, or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

XIII. SIGNATURES

IN WITNESS WHEREOF, the Parties hereto have caused two originals of this Agreement to be executed by their duly authorized representatives. This Agreement is effective as of the last date set forth below.

Interconnection Customer

By: ____________________________

Name: ____________________________

Title: ____________________________

Date: ____________________________

Company Operator

By: ____________________________

Name: ____________________________

Title: ____________________________

Date: ____________________________

EXHIBIT A

GENERATION SYSTEM DESCRIPTION AND SINGLE-LINE DIAGRAM

(Site specific, TBD)

EXHIBIT B

SUMMARY OF COMPANY COSTS AND DESCRIPTION OF DEDICATED FACILITIES BEING INSTALLED BY THE COMPANY OPERATOR FOR THE INTERCONNECTION OF THE GENERATION SYSTEM

This Exhibit shall provide the estimated total costs that will be the responsibility of the Interconnection Customer. It is assumed that the Initial application has been filed and the engineering studies have been paid for and completed. Therefore, those costs are not included on this listing.

What is listed below is a general outline of some of the major areas where costs could occur. Other costs than those listed below may be included by the Company if those costs are a direct result from the request to interconnect the Generation System. The following list is only a guideline and the Company Operator, for each installation, will be creating a unique Exhibit B that is tailored for that specific Generation System interconnection.

A) Dedicated Facilities (equipment, design, and installation labor)

B) Monitoring & Control System (equipment, design, and installation labor)

C) Design Coordination and Review

D) Construction Coordination Labor Costs

E) Testing (development of tests and physical testing)

F) Contingency

EXHIBIT C

ENGINEERING DATA SUBMITTAL

Attach a completed "Engineering Data Submittal" form from Appendix C of "Interconnection Process for Distributed Generation Systems".

EXHIBIT D

OPERATING AGREEMENT

Each Generation System interconnection will be unique and will require a unique Operating Agreement. The following is a listing of some of the possible areas that will be covered in an operating agreement. The following has not been developed into a standard agreement due to the unique nature of each Generation System. It is envisioned that this Exhibit will be tailored by the Company Operator for each Generation System interconnection. It is also intended that this Operating Agreement Exhibit will be reviewed and updated periodically to allow the operation of the Generation System to change to meet the needs of both the Company Operator and the Interconnection Customer, if the change does not negatively affect the other Party. There may also be operating changes required by outside issues such has changes in FERC and MISO requirements and/or policies which will require this Operating Agreement to be modified.

The following items are provided to show the general types of items that may be included in this Operating Agreement. The items included in the Operating Agreement shall not be limited to the items shown on this list.

A) Applicable Company Tariffs -- Discussion on which tariffs are being applied for this installation and possibly how they will be applied.

B) Var Requirements -- How will the Generation System be required to operate to control the power factor of the energy flowing in either direction across the interconnection.

C) Inadvertent Energy -- This Operating Agreement needs to provide the method(s) that will be used to monitor, meter, and account for the inadvertent energy used or supplied by the Generation System. Tariffs and operating rules that apply for this Generation System interconnection shall be discussed in this Operating Agreement.

D) Control Issues - Starting and stopping of the generation including the remote starting and stopping, if applicable.

E) Dispatch of Generation Resources - What are the dispatch requirements for the Generation System? Can it only run during Peak Hours? Are there a limited number of hours that it can run? Is it required to have met an availability percentage? This will greatly depend upon the PPA and other requirements. Is the Interconnection Customer required to coordinate outages of the Generation System with the Company?

F) Outages of Distribution System -- How are emergency outages handled? How are other outages scheduled? If the Interconnection Customer requires the Company Operator to schedule the outages during after-hours, who pays for the Company Operator's overtime?

G) Notification / Contacts - Who should be notified? How should they be notified? When should they be notified? For what reasons should the notification take place?

1) Starting of the Generation

2) Dispatching of Generation

3) Notification of failures (both Company and Generation System failures)

H) Documentation of Operational Settings – How much fuel will the generation System typically have on hand? How long can it run with this fuel capacity? How is the generation system set to operate for a power failure? These may be issues that should be documented in the Operating Agreement. The following are a couple of examples:

1) "The Generation System will monitor the Company phase voltage and after 2 seconds of any phase voltage below 90% the generation will be started and the load transferred to the generator if the generation is not already running."

2) "The Generation System will wait for 30 minutes after it senses the return of the Company frequency and voltage before it will automatically reconnect to the Company."

I) <u>Cost of testing for future failures</u> – If a component of the Generation System fails or needs to be replaced, which effects the interconnection with the Company, what is the process for retesting and for replacement? Who pays for the additional costs of the Company to work with the Interconnection Customer to resolve these problems and/or to complete retesting of the modified equipment?

J) <u>Right of Access</u> - At all times, the Company Operator shall have access to the disconnect switch of the Generation System for any reasonable purpose in connection with the performance of the obligations imposed on it by this Agreement to meet its obligation to operate the Company safely and to provide service to its customers. If necessary for the purposed of this Agreement, the Interconnection Customer shall allow the Company Operator access to the Company's equipment and facilities located on the premises.

Add Signature Section -The Operating Agreement should be set up so that it is individually signed and dated by both parties.

EXHIBIT E

MAINTENANCE AGREEMENT

Each Generation System interconnection will be unique and will require a unique Maintenance Agreement. It is envisioned that this Exhibit will be tailored for each Generation System interconnection. It is also intended that this Maintenance Agreement Exhibit will be reviewed and updated periodically to allow changes to the maintenance of the Generation System to meet the needs of both the Company Operator and the Interconnection Customer, if the change does not negatively affect the other Party. There may also be changes required by outside issues such has changes in FERC and MISO requirements and/or policies that will require this agreement to be modified.

A) Routine Maintenance Requirements

1) Who is providing maintenance – Contact information

2) Periods of maintenance

B) <u>Modifications to the Generation System</u> - The Interconnection Customer shall notify the Company Operator, in writing of plans for any modifications to the Generation System interconnection equipment at least twenty (20) business days before undertaking such modification. Modifications to any of the interconnection equipment including all required protective systems, the generation control systems, the transfer switches/breakers, VT's & CT's, generating capacity, and associated wiring shall be included in the written notification to the Company Operator. The Interconnection Customer agrees not to commence installation of any modifications to the Generating System until the Company Operator has approved the modification, in writing. The Company shall have a minimum of five (5) business days and a maximum of ten (10) business days to review and respond to the modification after the receipt of the information required to review the modifications.

Add signature Section

INTERCONNECTION REQUIREMENTS FOR EXTENDED PARALLELED DISTRIBUTION GENERATION SYSTEMS

TABLE OF CONTENTS

Foreword

Electric distribution system connected generation units span a wide range of sizes and electrical characteristics. Electrical distribution system design varies widely from that required to serve the rural customer to that needed to serve the large commercial customer. With so many variations possible, it becomes complex and difficult to create one interconnection standard that fits all generation interconnection situations.

In establishing a generation interconnection standard, there are three main issues that must be addressed: Safety, Economics, and Reliability.

The first and most important issue is safety; the safety of the general public and of the employees working on the electrical systems. This standard establishes the technical requirements that must be met to ensure the safety of the general public and the employees working with the Company. Typically, designing the interconnection system for the safety of the general public will also provide protection for the interconnected equipment.

The second issue is economics. The interconnection design must be affordable to build. The interconnection standard must be developed so that only those items that are necessary to meet safety and reliability are included in the requirements. This standard sets the benchmark for the minimum required equipment. If it is not needed, it will not be required.

The third issue is reliability. The generation system must be designed and interconnected such that the reliability and the service quality for all customers of the electrical power system are not compromised. This applies to all electrical systems not just the Company's.

Many generation interconnection standards exist or are in draft form. The IEEE, FERC, and many states have been working on generation interconnection standards. There are other standards, such as the National Electrical Code (NEC), that establish requirements for electrical installations. The NEC requirements are in addition to this standard. This standard is designed to document the requirements where the NEC has left the establishment of the standard to "the authority having jurisdiction" or to cover issues that are not covered in other national standards.

This standard covers installation, with an aggregated capacity of 10 MWs or less. Many of the requirements in this document do not apply to small, 20 kW or less generation installations.

1. Introduction

This standard has been developed to document the technical requirements for the interconnection between a Generation System and Company's electric distribution system. This standard covers 3-phase Generation Systems with an aggregate capacity of 10 MWs or less and single-phase Generation Systems with a aggregate capacity of 20 kW or less at the Point of Common Coupling. This standard covers Generation Systems that are interconnected with the Company's distribution facilities. This standard does not cover Generation Systems that are directly interconnected with the Company's Transmission System. Contact the Company for their Transmission System interconnection standards.

While this standard provides the technical requirements for interconnecting a Generation System with a typical radial distribution system, it is important to note that there are some unique areas of the Company's distribution system that have special interconnection needs. One example of a unique area would be one operated as a "networked" system. This standard does not cover the additional special requirements of those systems. The Interconnection Customer must contact the Company Operator to make sure that the Generation System is not proposed for a unique area system. If the planned interconnection is with a unique area, the Interconnection Customer must obtain the additional requirements for interconnecting.

The Company Operator has the right to limit the maximum size of any Generation System or number of Generation Systems that may want to interconnect if the Generation System would reduce the reliability to the other customers connected to the Company.

This standard only covers the technical requirements and does not cover the interconnection process from the planning of a project through approval and construction. Please read the companion document "Interconnection Process for Distributed Generation Systems" for the description of the procedure to follow and the forms to submit. It is important to also get copies of the Company's tariffs concerning generation interconnection which will include rates, costs, and standard conditions. The earlier the Interconnection Customer gets the Company Operator involved in the planning and design of the Generation System interconnection, the smoother the process will go.

A) Definitions

The definitions defined in the "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems", IEEE 1547, apply to this document as well. The following definitions are in addition to the ones defined in IEEE 1547, or are repeated from the IEEE 1547 standard.

i) "Area EPS" – the area electric power system that is also referred to as the Company electric distribution system in this document.

ii) "Company" - an electric power system (EPS) that serves the Local EPS. Note: Typically, the Company has primary access to public rights-of-way, priority crossing of property boundaries, etc.

iii) "Generation" - any device producing electrical energy; i.e., rotating generators driven by wind, steam turbines, internal combustion engines, hydraulic turbines, solar, fuel cells, etc.; or any other electric producing device including energy storage technologies.

iv) "Generation System" - the interconnected Distributed Generation(s), controls, relays, switches, breakers, transformers, inverters, and associated wiring and cables up to the Point of Common Coupling.

v) "Interconnection Customer" - the party or parties who are responsible for meeting the requirements of this standard. This could be the Generation System applicant, installer, designer, owner, or operator.

vi) "Local EPS" - an electric power system (EPS) contained entirely within a single premises or group of premises.

vii) "Open Transfer" - a method of transferring the local loads from the Company to the generator such that the generator and the Company are never connected together.

viii) "Point of Common Coupling" - the point where the Local EPS is connected to the Company's system.

ix) "Quick Closed" - a method of generation transfer that parallels for less than 100 msec with the Company and has utility grade timers that limit the parallel duration to less then 100 msec with the Company.

x) "Quick Open" - a method of generation transfer that does not parallel with the Company and has a brief open interval, typically about 100 msec.

xi) "Soft Loading Transfer" - a method of generation load transfer that parallels for typically less than 2 minutes to gradually transfer load between the generator and the Company.

xii) "Transmission System" - those facilities as defined by using the guidelines established by FERC.

xiii) "Type-Certified" - Generation paralleling equipment that is listed by an OSHA listed national testing laboratory as having met the applicable type-testing requirements of IEEE 1547.1, such as UL 1741. This definition does not preclude other forms of type-certification if agreeable to the Company Operator. "Type-Certified" is the same as "pre-certified" and "certified" when used in this text.

B) Interconnection Requirements Goals

This standard defines the minimum technical requirements for the implementation of the electrical interconnection between the Generation System and the Company. It does not define the overall requirements for the Generation System. The requirements in this standard are intended to achieve the following:

i) Ensure the safety of utility personnel and contractors working on the electrical power system.

ii) Ensure the safety of utility customers and the general public.

iii) Protect and minimize the possible damage to the electrical power system and other customer's property.

iv) Ensure proper operation to minimize adverse operating conditions on the electrical power system.

C) Protection

The Generation System and Point of Common Coupling shall be designed with proper protective devices to promptly and automatically disconnect the Generation from the Company in the event of a fault or other system abnormality. The type of protection required will be determined by:

i) Size and type of the generating equipment.

ii) The method of connecting and disconnecting the Generation System from the electrical power system.

iii) The location of generating equipment on the Company's system.

D) Company Modifications

Depending upon the match between the Generation System, the Company, and how the Generation System is operated, certain modifications and/or additions may be required to the existing Company system with the addition of the Generation System. To the extent possible, this standard describes the modifications that could be necessary to the Company facilities for different types of Generation Systems. For some unique interconnections, additional and/or different protective devices, system modifications, and/or additions will be required by the Company Operator. In these cases, the Company Operator will provide the final determination of the required modifications and/or additions. If any special requirements are necessary, the Company Operator will identify them during the application review process.

E) Generation System Protection

The Interconnection Customer is solely responsible for providing protection for the Generation System. Protection systems required in this standard are structured to protect the Company's electrical power system and the public. The Generation System Protection is not provided for in this standard. Additional protection equipment may be required to ensure proper operation for the Generation System. This is especially true while operating disconnected from the Company. The Company does not assume responsibility for protection of the Generation System equipment or of any portion of the Local EPS.

F) Electrical Code Compliance

The Interconnection Customer shall be responsible for complying with all applicable local, independent, state, and federal codes such as building codes, National Electric Code (NEC), National Electrical Safety Code (NESC), and noise and emissions standards. The Company will require proof of complying with the National Electrical Code before the interconnection is made through installation approval by an electrical inspector.

The Interconnection Customer's Generation System and installation shall comply with latest revisions of the ANSI/IEEE standards applicable to the installation, especially IEEE 1547; "Standard for Interconnecting Distributed Resources with Electric Power Systems" and IEEE 1547.1 – 1547.6. See the reference section in this document for a partial list of the standards that apply to the generation installations covered by this standard.

2. References

The following standards shall be used in conjunction with this standard. When the stated version of the following standards is superseded by an approved revision, then that revision shall apply.

IEEE Std 100-2000, "IEEE Standard Dictionary of Electrical and Electronic Terms".

IEEE Std 519-1992, "IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems".

IEEE Std 519-1992, "IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems".

IEEE Std 1547-2003, "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems".

IEEE Std 1547.1-2005, "IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems".

IEEE Std C37.90.1-1989 (1995), "IEEE Standard Surge Withstand Capability (SEC) Tests for Protective Relays and Relay Systems".

IEEE Std C37.90.2 (1995), "IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers".

IEEE Std C62.41.2-2002, "IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits".

IEEE Std C62.42-1992 (2002), "IEEE Recommended Practice on Surge Testing for Equipment Connected to Low Voltage (1000V and less) AC Power Circuits".

ANSI C84.1-1995, "Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)".

ANSI/IEEE 446-1995, "Recommended Practice for Emergency and Standby Power Systems for Industrial and Commercial Applications".

ANSI/IEEE Standard 142-1991, "IEEE Recommended Practice for Grounding of Industrial an Commercial Power Systems – Green Book",

UL Std. 1741 "Inverters, Converters, and Controllers for use in Independent Power Systems".

NEC – "National Electrical Code", National Fire Protection Association (NFPA), NFPA-70-2002.

NESC – "National Electrical Safety Code". ANSI C2-2002, Published by the Institute of Electrical and Electronics Engineers, Inc.

3. Types of Interconnections

A) The manner in which the Generation System is connected to and disconnected from the Company can vary. Most transfer systems normally operate using one of the following five methods of transferring the load from the Company to the Generation System.

B) If a transfer system is installed which has a user accessible selection of several transfer modes, the transfer mode that has the greatest protection requirements will establish the protection requirements for that transfer system.

i) Open Transition (Break-Before-Make) Transfer Switch – With this transfer switch, the load to be supplied from the Distributed Generation is first disconnected from the Company and then connected to the Generation. This transfer can be relatively quick, but voltage and frequency excursions are to be expected during transfer. Computer equipment and other sensitive equipment will shut down and reset. The transfer switch typically consists of a standard UL approved transfer switch with mechanical interlocks between the two source contactors that drop the Company source before the Distributed Generation is connected to supply the load.

(1) To qualify as an Open Transition switch and the limited protective requirements, mechanical interlocks are required between the two source contacts. This is required to ensure that one of the contacts is always open and the Generation System is never operated in parallel with the Company. If the mechanical interlock is not present, the protection requirements are as if the switch is a closed transition switch.

(2) As a practical point of application, this type of transfer switch is typically used for loads less then 500 kW.

This is due to possible voltage flicker problems created on the Company when the load is removed from or returned to the Company source. Depending up the Company system's stiffness, this level may be larger or smaller than the 500 kW level.

(3) Figure 1 at the end of this document provides a typical one-line of this type of installation.

ii) Quick Open Transition (Break-Before-Make) Transfer Switch – The load to be supplied from the Distributed Generation is first disconnected from the Company and then connected to the Distributed Generation, similar to the open transition. However, this transition is typically much faster (under 500 ms) than the conventional open transition transfer operation. Voltage and frequency excursions will still occur, but some computer equipment and other sensitive equipment will typically not be affected with a properly designed system. The transfer switch consists of a standard UL approved transfer switch with mechanical interlocks between the two source contacts that drop the Company source before the Distributed Generation is connected to supply the load.

(1) Mechanical interlocks are required between the two source contacts to ensure that one of the contacts is always open. If the mechanical interlock is not present, the protection requirements are as if the switch is a closed transition switch

(2) As a practical point of application, this type of transfer switch is typically used for loads less then 500 kW. This is due to possible voltage flicker problems created on the Company, when the load is removed from or returned to the Company source. Depending up the Company system's stiffness, this level may be larger or smaller than the 500 kW level.

(3) Figure 2 at the end of this document provides a typical one-line of this type of installation and shows the required protective elements.

iii) Closed Transition (Make-Before-Break) Transfer Switch -- The Distributed Generation is synchronized with the Company before the transfer occurs. The transfer switch then parallels with the Company for a short time (100 msec. or less) and then the Generation System and load is disconnect from the Company. This transfer is less disruptive than the Quick Open Transition because it allows the Distributed Generation a brief time to pick up the load before the support of the Company is lost. With this type of transfer, the load is always being supplied by the Company or the Distributed Generation.

(1) As a practical point of application, this type of transfer switch is typically used for loads less then 500 kW. This is due to possible voltage flicker problems created on the Company, when the load is removed from or returned to the Company source. Depending up the Company system's stiffness, this level may be larger or smaller than the 500 kW level.

(2) Figure 2 at the end of this document provides a typical one-line of this type of installation and shows the required protective elements. The closed transition switch must include a separate parallel time limit relay, which is not part of the generation control PLC and trips the generation from the system for a failure of the transfer switch and/or the transfer switch controls.

iv) Soft Loading Transfer Switch

(1) With Limited Parallel Operation – The Distributed Generation is paralleled with the Company for a limited amount of time (generally less then 1-2 minutes) to gradually transfer the load from the Company to the Generation System. This minimizes the voltage and frequency problems by softly loading and unloading the Generation System.

(a) The maximum parallel operation shall be controlled via a parallel timing limit relay (62PL). This parallel time limit relay shall be a separate relay and not part of the generation control PLC.

(b) Protective Relaying is required as described in Section 6.

(c) Figure 3 at the end of this document provides a typical one-line diagram of this type of installation and shows the required protective elements.

(2) With Extended Parallel Operation – The Generation System is paralleled with the Company in continuous operation. Special design, coordination, and agreements are required before any extended parallel operation will be permitted. The Company interconnection study will identify the issues involved.

(a) Any anticipated use in the extended parallel mode requires special agreements and special protection coordination.

(b) Protective Relaying is required as described in Section 6.

(c) Figure 4 at the end of this document provides a typical one-line diagram for this type of interconnection. It must be emphasized that these are a typical installations only and final installations may vary from the examples shown due to transformer connections, breaker configuration, etc.

v) Inverter Connection

This is a continuous parallel connection with the system. Small Generation Systems may utilize inverters to interface to the Company. Solar, wind, and fuel cells are some examples of Generation that typically use inverters to connect to the Company. Either these inverters shall contain all necessary protection to prevent unintentional islanding or the Interconnection Customer shall install conventional protection to affect the same protection. All required protective elements for a soft-loading transfer switch apply to an inverter connection. Figure 5 at the end of this document, shows a typical inverter interconnection.

(1) Inverter Certification – Before installation, the inverter shall be Type-Certified for interconnection to the electrical power system. The certification will confirm its anti-islanding protection and power quality related levels at the Point of Common Coupling. Also, utility compatibility, electric shock hazard, and fire safety are approved through UL listing of the model. Once this Type Certification is completed for that specific model, additional design review of the inverter should not be necessary by the Company Operator.

(2) For three-phase operation, the inverter control must also be able to detect and separate for the loss of one phase. Larger inverters will still require custom protection settings, which must be calculated and designed to be compatible with the specific Company system.

(3) A visible, lockable loadbreak disconnect switch is required for safety to isolate the Distributed Generation. The inverter shall not be used as a safety isolation device.

(4) When banks of inverter systems are installed at one location, a design review by the Company must be preformed to determine any additional protection systems, metering, or other needs. The issues will be identified by the Company during the interconnection study process

4. Interconnection Issues and Technical Requirements

A) General Requirements - The following requirements apply to all interconnected generating equipment. The Company shall be the source side and the customer's system shall be the load side in the following interconnection requirements.

i) Visible, Lockable Loadbreak Disconnect Switch - A disconnecting device shall be installed to electrically isolate the Company from the Generation System. The only exception for the installation of a visible, lockable loadbreak disconnect is if the generation is interconnected via a mechanically interlocked open transfer switch and installed per the NEC (702.6) "so as to prevent the inadvertent interconnection of normal and alternate sources of supply in any operation of the transfer equipment."

The visible, lockable loadbreak disconnect shall provide a visible air gap between Interconnection Customer's Generation and the Company in order to establish the safety isolation required for work on the Company system. This disconnecting device shall be readily accessible 24 hours per day by the Company field personnel and shall be capable of padlocking by the Company field personnel. The disconnecting device shall be lockable in the open position. In general, the device is not considered accessible if site personnel must be contacted or used to access and/or operate the device.

The visible, lockable loadbreak disconnect shall be a UL approved or National Electrical Manufacture's

Association approved, manual safety disconnect switch of adequate ampere capacity. The visible disconnect shall not open the neutral when the switch is open. A draw-out type circuit breaker can be used as a visual open as long as it meets the Company field personnel accessibility requirement.

The visible disconnect shall be labeled, as required by the Company Operator to inform the Company field personnel.

ii) Energization of Equipment by Generation System – The Generation System shall not energize a de-energized Company system. The Interconnection Customer shall install the necessary padlocking (lockable) devices on equipment to prevent the energization of a de-energized electrical power system. Lock out relays shall automatically block the closing of breakers or transfer switches on to a de-energized Company system.

iii) Power Factor - The power factor of the Generation System and connected load shall be as follows:

(1) Inverter Based interconnections – for 20 kW and less, shall operate at a power factor of no less then 90% at the inverter terminals. Facilities over 20 kW shall meet the extended parallel requirements.

(2) Limited Parallel Generation Systems, such as closed transfer or soft-loading transfer systems shall operate at a power factor of no less then 90% during the period when the Generation System is parallel with the Company as measured at the Point of Common Coupling.

(3) Extended Parallel Generation Systems shall be designed to be capable of operating between 90% lagging and 95% leading. These Generation Systems shall operate near unity power factor (+/-98%) or as mutually agreed between the Company Operator and the Interconnection Customer.

iv) Grounding Issues

(1) Grounding of sufficient size to handle the maximum available ground fault current shall be designed and installed to limit step and touch potentials to safe levels as set forth in "IEEE Guide for Safety in AC Substation Grounding", ANSI/IEEE Standard 80.

(2) It is the responsibility of the Interconnection Customer to provide the required grounding for the Generation System. A good standard for this is the IEEE Std. 142-1991 "Grounding of Industrial and Commercial Power Systems"

(3) All electrical equipment shall be grounded in accordance with local, state, and federal electrical and safety codes, and applicable standards

v) Sales to Company or other parties – Transportation of energy on the Transmission system is regulated by the area reliability council and FERC. Those contractual requirements are not included in this standard. The Company will provide these additional contractual requirements during the interconnection approval process.

B) For Inverter based, closed transfer and soft loading interconnections - The following additional requirements apply:

i) Fault and Line Clearing - The Generation System shall be removed from the Company system for any faults, or outages occurring on the electrical circuit serving the Generation System.

ii) Operating Limits - in order to minimize objectionable and adverse operating conditions on the electric service provided to other customers connected to the Company, the Generation System shall meet the Voltage, Frequency, Harmonic and Flicker operating criteria as defined in IEEE 1547 and IEEE 519 standards during periods when the Generation System is operated in parallel with the Company.

If the Generation System creates voltage changes greater than 4% on the Company system, it is the responsibility of the Interconnection Customer to correct these voltage sag/swell problems caused by the operation of the Generation System. If the operation of the interconnected Generation System causes flicker, which causes problems for others customer's interconnected to the Company, the Interconnection Customer is responsible for correcting the problem.

iii) Flicker - The operation of the Generation System is not allowed to produce excessive flicker to adjacent customers. See IEEE 1547 and IEEE 519 standards for a more complete discussion on this requirement.

The stiffer the Company system, the larger a block load change that it will be able to handle. For any of the transfer systems, the Company voltage shall not drop or rise greater than 4% when the load is added or removed from the Company. It is important to note, that if another interconnected customer complains about the voltage change caused by the Generation System, even if the voltage change is below the 4% level, it is the Interconnection Customer's responsibility to correct or pay for correcting the problem. Utility experience has shown that customers have seldom objected to instantaneous voltage changes of less then 2% on the Company system.

iv) Interference - The Interconnection Customer shall disconnect the Distributed Generation from the Company if the Distributed Generation causes radio, television, or electrical service interference to other customers, via the distribution system or interference with the operation of the Company's system. The Interconnection Customer either shall effect repairs to the Generation System or reimburse the Company Operator for the cost of any required modifications address the interference.

v) Synchronization of Customer Generation-

(1) An automatic synchronizer with synch-check relaying is required for unattended automatic quick open transition, closed transition, or soft loading transfer systems.

(2) To prevent unnecessary voltage fluctuations on the Company system, it is required that the synchronizing equipment be capable of closing the Distributed Generation into the Company system within the limits defined in IEEE 1547. Actual settings shall be determined by the Registered Professional Engineer establishing the protective settings for the installation.

(3) Unintended Islanding – Under certain conditions with extended parallel operation, it would be possible for a part of the Company's system to be disconnected from the rest of the Company's system and have the Generation System continue to operate and provide power to a portion of the isolated circuit. This condition is called "islanding". It is not possible to successfully reconnect the energized isolated circuit to the rest of the Company's system since there are no synchronizing controls associated with all of the possible locations of disconnection. Therefore, it is a requirement that the Generation System be automatically disconnected from the Company's system immediately by protective relays for any condition that would cause the Company's system to be de-energized. The Generation System must either isolate with the customer's load or trip. The Generation System must also be blocked from closing back into the Company's system until the Company's system is reenergized and the voltage is within Range B of ANSI C84.1 Table 1 for a minimum of 1 minute. Depending upon the size of the Generation System, it may be necessary to install direct transfer trip equipment from the Company's source(s) to remotely trip the generation interconnection to prevent islanding for certain conditions

vi) Disconnection – the Company Operator may refuse to connect or may disconnect a Generation System from the Company under the following conditions:

(1) Lack of approved Standard Application Form and Standard Interconnection Agreement.

(2) Termination of interconnection by mutual agreement.

(3) Non-Compliance with the technical or contractual requirements.

(4) System Emergency or for imminent danger to the public or Company personnel (Safety).

(5) Routine maintenance, repairs, and modifications to the Company. The Company Operator shall coordinate planned outages with the Interconnection Customer to the extent practical.

5. Generation Metering, Monitoring, and Control

Metering, Monitoring and Control -- Depending upon the method of interconnection and the size of the Generation System, there are different metering, monitoring, and control requirements. Table 5A summarizes the metering, monitoring, and control requirements.

Due to the variation in Generation Systems and Company operational needs, the requirements for metering, monitoring, and control listed in this document are the expected maximum requirements that the Company will apply to the Generation System. It is important to note that for some Generation System installations, the Company may waive some of the requirements of this section if they are not needed. An example of this is with rural or low capacity feeders that require more monitoring then larger capacity, typically urban feeders.

Another factor that will effect the metering, monitoring, and control requirements will be the tariff under which the Interconnection Customer is supplied by the Company. Table 5A has been written to cover most application but some Company tariffs may have greater or lesser metering, monitoring, and control requirements than shown in Table 5A.

TABLE 5A
Metering, Monitoring, and Control Requirements

Generation System Capacity at Point of Common Coupling	Metering	Generation Remote Monitoring	Generation Remote Control
< 20 kW with all sales to Company	Bi-Directional metering at the point of common coupling**	None Required	None Required
20 – 250 kW with limited parallel	Detented* Company Metering at the Point of Common Coupling	None Required	None Required
20 – 250 kW with extended parallel	Recording metering on the Generation System and a separate recording meter on the load	Interconnection Customer supplied direct dial phone line. Company to supply it's own monitoring equipment	None Required
250 – 1000 kW With limited parallel	Detented* Company Metering at the Point of Common Coupling	Interconnection Customer supplied direct dial phone line and monitoring points available. See B (i)	None Required
250 – 1000 kW With extended parallel operation	Recording metering on the Generation System and a separate recording meter on the load.	Required Company remote monitoring system See B (i)	None Required
>1000 kW With limited parallel Operation	Detented* Company Metering at the Point of Common Coupling	Required Company SCADA monitoring system. See B (i)	None required
>1000 kW With extended parallel operation	Recording metering on the Generation System and a separate recording meter on the load.	Required Company SCADA monitoring system See B (i)	Direct Control via SCADA by Company of interface breaker.

* "Detented" - A meter that is detented will record power flow in only one direction.

** Meter will be detented unless a specific Company tariff permits net metering and the Interconnection customer has arranged for this service.

A) Metering

i) As shown in Table 5A, the requirements for metering will depend up on the type of generation and the type of interconnection. For most installations, the requirement is a single point of metering at the Point of Common Coupling. The Company Operator will install a special meter that is capable of measuring and recording energy flow in both directions, for three-phase installations or two detented meters wired in series, for single-phase installations. A dedicated, direct dial phone line may be required to be supplied to the meter for the Company's use to read the metering. Some monitoring may be done through the meter and the dedicated, direct dial phone line. In many installations, the remote monitoring and the meter reading can be done using the same dial-up phone line. The actual metering configuration and meters installed will be in accordance with the application and the tariffs that apply to the facility.

ii) Depending upon which tariff under which the Generation System and/or customer's load is being supplied, additional metering requirements may result. Contact the Company for tariff requirements. In some cases, the direct dial-phone line requirement may be waived by the Company for smaller Generation Systems.

iii) All Company's revenue meters shall be supplied, owned, and maintained by the Company. All voltage transformers (VT) and current transformers (CT) used for revenue metering shall be approved and/or supplied by the Company. The Company's standard practices for instrument transformer location and wiring shall be followed for the revenue metering.

iv) An additional, separate meter may be required to record energy for renewable energy credit (REC) payments. This will be determined by the present tariffs on file and approved by the Commission.

B) Monitoring (SCADA) is required as shown in table 5A. The need for monitoring is based on the need of the system control center to have the information necessary for the reliable operation of the Company's system. This remote monitoring is especially important during periods of abnormal and emergency operation.

The difference in Table 5A between remote monitoring and SCADA is that SCADA typically is a system that is in continuous communication with a central computer and provides updated values and status to the Company Operator within several seconds of the changes in the field. Remote monitoring on the other hand will tend to provide updated values and status within minutes of the change in state of the field. Remote monitoring is typically less expensive to install and operate.

i) Where Remote Monitoring or SCADA is required, as shown in Table 5A, the following monitored and control points are required:

(1) Real and reactive power flow for each Generation System (kW and kVAr). Only required if separate metering of the Generation and the load is required, otherwise #4 monitored at the point of Common Coupling will meet the requirements.

(2) Phase voltage representative of the Company's service to the facility.

(3) Status (open/close) of Distributed Generation and interconnection breaker(s) or if a transfer switch is used, status of transfer switch(s).

(4) Customer load from Company service (kW and kVAr).

(5) Control of interconnection breaker - if required by the Company Operator.

When telemetry is required, the Interconnection Customer must provide the communications medium to the Company's Control Center. This could be radio, dedicated phone circuit, or other form of communication. If a telephone circuit is used, the Interconnection Customer must also provide the telephone circuit protection. The Interconnection Customer shall coordinate the RTU (remote terminal unit) addition with the Company. The Company may require a specific RTU and/or protocol to match their SCADA or remote monitoring system.

6. Protective Devices and Systems

A) Protective devices required to permit safe and proper operation of the Company while interconnected with customer's Generation System are shown in the figures at the end of this document. In general, an increased degree of protection is required for increased Distributed Generation size. This is due to the greater magnitude of short circuit currents and the potential impact to system stability from these installations. Medium and large installations require more sensitive and faster protection to minimize damage and ensure safety. The relaying requirements illustrated are typical requirements. Additional requirements may be needed to accommodate the Facility. Additional requirements are likely where the Facility size is large compared to the system capacity and short circuit strength.

If a transfer system is installed that has a user accessible selection of several transfer modes, the transfer mode that has the greatest protection requirements will establish the protection requirements for that transfer system.

The Interconnection Customer shall provide protective devices and systems to detect the Voltage, Frequency, Harmonic, and Flicker levels as defined in the IEEE 1547 standard during periods when the Generation System is operated in parallel with the Company. The Interconnection Customer shall be responsible for the purchase, installation, and maintenance of these devices. Discussion on the requirements for these protective devices and systems follows:

i) Relay settings

(1) If the Generation System is utilizing a Type-Certified system, such as a UL listed inverter a Professional Electrical Engineer is not required to review and approve the design of the interconnecting system. If the Generation System interconnecting device is not Type-Certified or if the Type-Certified Generation System interconnecting device has additional design modifications made, the Generation System control, the protective system, and the interconnecting device(s) shall be reviewed and approved by a Professional Electrical Engineer registered in the State.

(2) A copy of the proposed protective relay settings shall be supplied to the Company Operator for review and approval to ensure proper coordination between the generation system and the Company.

ii) Relays

(1) All equipment providing relaying functions shall meet or exceed ANSI/IEEE Standards for protective relays; i.e., C37.90, C37.90.1 and C37.90.2.

(2) Required relays that are not "draw-out" cased relays shall have test plugs or test switches installed to permit field testing and maintenance of the relay without unwiring or disassembling the equipment. Installations 20 kW and under utilizing Type-Certified interconnection equipment are exempt from this requirement. The Company may waive compliance with this requirement for larger installations utilizing Type-Certified equipment in some situations.

(3) Three phase interconnections shall utilize three-phase power relays that monitor all three phases of voltage and current, unless otherwise noted in the appendix one-lines.

(4) All relays shall be equipped with setting limit ranges at least as wide as specified in IEEE 1547 and meet other requirements as specified in the Company interconnect study. Setting limit ranges are not to be confused with the actual relay settings required for the proper operation of the installation. At a minimum, all protective systems shall meet the requirements established in IEEE 1547.

(a) <u>Over-current relays</u> (IEEE Device 50/51 or 50/51V) shall operate to trip the protecting breaker at a level to ensure protection of the equipment and at a speed to allow proper coordination with other protective devices. For example, the over-current relay monitoring the interconnection breaker shall operate fast enough for a fault on the customer's equipment, so that no protective devices will operate on the Company's system. 51V is a voltage restrained or controlled over-current relay and may be required to provide proper coordination with the Company.

(b) <u>Over-voltage relays</u> (IEEE Device 59) shall operate to trip the Distributed Generation per the requirements of IEEE 1547.

(c) Under-voltage relays (IEEE Device 27) shall operate to trip the Distributed Generation per the requirements of IEEE 1547

(d) Over-frequency relays (IEEE Device 81O) shall operate to trip the Distributed Generation off-line per the requirements of IEEE 1547.

(e) Under-frequency relay (IEEE Device 81U) shall operate to trip the Distributed Generation off-line per the requirements of IEEE 1547. For Generation Systems with an aggregate capacity greater then 20 kW, the Distribution Generation shall trip off-line when the frequency drops below 57.0-59.8 Hz. typically this is set at 59.5 Hz, with a trip time of 0.16 seconds, but coordination with the Company is required for this setting.

The Company will provide the reference frequency of 60 Hz. The Distributed Generation control system must be used to match this reference. The protective relaying in the interconnection system will be expected to maintain the frequency of the output of the Generation.

(f) Reverse power relays (IEEE Device 32) (power flowing from the Generation System to the Company) shall operate to trip the Distributed Generation off-line for a power flow to the system with a maximum time delay of 2.0 seconds.

(g) Lockout Relay (IEEE Device 86) is a mechanically locking device which is wired into the close circuit of a breaker or switch and when tripped will prevent any close signal from closing that device. This relay requires that a person manually resets the lockout relay before that device can be reclosed. These relays are used to ensure that a de-energized system is not reenergized by automatic control action and prevents a failed control from auto-reclosing an open breaker or switch.

(h) Transfer Trip – All Generation Systems are required to disconnect from the Company when the Company's system is disconnected from its source to avoid unintentional islanding. With larger Generation Systems, which remain in parallel with the Company, a transfer trip system may be required to sense the loss of the Company source. When the Company source is lost, a signal is sent to the Generation System to separate the Generation from the Company. The size of the Generation System versus the capacity and minimum loading on the feeder will dictate the need for a transfer trip installation. The Company interconnection study will identify the specific requirements.

If multiple Company sources are available or there are multiple points of sectionalizing on the Company system, then more than one transfer trip system may be required. The Company interconnection study will identify the specific requirements. For some installations, the alternate Company source(s) may not be utilized except in rare occasions. If this is the situation, the Interconnection Customer may elect to have the Generation System locked out when the alternate source(s) are utilized if agreeable to the Company Operator.

(i) Parallel limit timing relay (IEEE Device 62PL) set at a maximum of 120 seconds for soft transfer installations and set no longer then 100 ms for quick transfer installations, shall trip the Distributed Generation circuit breaker on limited parallel interconnection systems. Power for the 62 PL relay must be independent of the transfer switch control power. The 62PL timing must be an independent device from the transfer control and shall not be part of the generation PLC or other control system.

TABLE 6A
SUMMARY OF RELAYING REQUIREMENTS

Type of Interconnection	Over-current (50/51)	Voltage (27/59)	Frequency (81 0/U)	Reverse Power (32)	Lockout (86)	Parallel Limit Timer	Sync-Check (25)	Transfer Trip
Open Transition Mechanically Interlocked (Fig. 1)	—	—	—	—	—	—	—	—
Quick Open Transition Mechanically Interlocked (Fig. 2)	—	—	—	—	Yes	Yes	Yes	—
Closed Transition (Fig. 2)	—	—	—	—	Yes	Yes	Yes	—
Soft Loading Limited Parallel Operation (Fig. 3)	Yes	Yes	Yes	Yes	Yes	Yes	Yes	—
Soft Loading Extended Parallel < 250 kW (Fig. 4)	Yes	Yes	Yes	—	Yes	—	Yes	—
Soft Loading Extended Parallel >250 kW (Fig. 4)	Yes	Yes	Yes	—	Yes	—	Yes	Yes
Inverter Connection (Fig. 5)								
< 20 kW	Yes	Yes	Yes	—	Yes	—	—	—
20 kW – 250 kW	Yes	Yes	Yes	—	Yes	—	—	—
> 250 kW	Yes	Yes	Yes	—	Yes	—	—	Yes

7. Agreements

A) Interconnection Agreement – This agreement is required for all Generation Systems that parallel with the Company. There may be different interconnection agreements depending upon the size and type of Generation System. This agreement contains the terms and conditions upon which the Generation System is to be connected, constructed, and maintained when operated in parallel with the Company. Some of the issues covered in the interconnection agreement are as follows;

i) Construction Process

ii) Testing Requirements

iii) Maintenance Requirements

iv) Firm Operating Requirements such as Power Factor

v) Access requirements for the Company personnel

vi) Disconnection of the Generation System (Emergency and Non-emergency)

vii) Term of Agreement

viii) Insurance Requirements

ix) Dispute Resolution Procedures

B) Operating Agreement -- For larger Generation Systems that normally operate in parallel with the Company, an agreement separate from the interconnection agreement, called the "operating agreement", is usually created. This agreement is created for the benefit of both the Interconnection Customer and the Company Operator and will be agreed to between the Parties. This agreement will be dynamic and is intended to be updated and reviewed annually. For some smaller systems, the operating agreement can simply be a letter agreement. For larger and more integrated Generation Systems, the operating agreement will tend to be more involved and more formal. The operating agreement covers items that are necessary for the reliable operation of the Customer's and Company's systems. The items typically included in the operating agreement are as follows;

i) Emergency and normal contact information for both the Company operations center and for the Interconnection Customer.

ii) Procedures for periodic Generation System test runs.

iii) Procedures for maintenance on the Company system that affect the Generation System.

iv) Emergency Generation Operation Procedures.

8. Testing Requirements

A) Pre-Certification of Equipment

The most important part of the process to interconnect generation with Customer's and Company's systems is safety. One of the key components of ensuring the safety of the public and employees is to ensure that the design and implementation of the elements connected to the electrical power system operate as required. To meet this goal, all of the electrical wiring in a business or residence is required to be listed by a recognized testing and certification laboratory for its intended purpose. Typically, we see this as "UL" listed. Since Generation Systems have tended to be uniquely designed for each installation, they have been designed and approved by Professional Engineers. As the number of Generation Systems installed increase, vendors are working towards creating equipment packages that can be tested in the factory and then will only require limited field testing. This will allow us to move towards "plug and play" installations. For this reason, this standard recognizes the efficiency of "pre-certification" of Generation System equipment packages that will help streamline the design and installation process.

An equipment package shall be considered certified for interconnected operation if it has been submitted by a manufacture to and tested and listed by a nationally recognized testing and certification laboratory (NRTL) for continuous utility interactive operation in compliance with the applicable codes and standards. The applicable type-testing requirements are given in IEEE 1547.1. An "equipment package" shall include all interface components including switchgear, inverters, or other interface devices and may include an integrated generator or electric source. If the equipment package has been tested and listed as an integrated package that includes a generator or other electric source, it shall not required further design review, testing, or additional equipment to meet the certification requirements for interconnection. If the equipment package includes only the interface components (switchgear, inverters, or other interface devices), then the Interconnection Customer shall show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and consistent with the testing and listing specified for the package. Provided the generator or electric source combined with the equipment package is consistent with the testing and listing performed by the nationally recognized testing and certification laboratory, no further design review, testing, or additional equipment shall be required to meet the certification requirements of this interconnection procedure. A certified equipment package does not include equipment provided by the Company.

The use of Pre-Certified equipment does not automatically qualify the Interconnection Customer to be interconnected to the Company. An application will still need to be submitted and an interconnection review may still need to be performed to determine the compatibility of the Generation System with the Company's system.

B) Pre-Commissioning Tests

i) Non-Certified Equipment

Pre-commissioning testing and Commissioning testing are also covered in IEEE 1547.1.

(1) Protective Relaying and Equipment Related to Islanding

(a) Distributed generation that is not Type-Certified (type-tested), shall be equipped with protective hardware and/or software designed to prevent the Generation from being connected to a de-energized Company system.

(b) The Generation may not close into a de-energized Company system and protection must be provided to prevent this from occurring. It is the Interconnection Customer's responsibility to provide a final design and to install the protective measures required by the Company. The Company will review and approve the design, the types of relays specified, and the installation. Mutually agreed upon exceptions may at times be necessary and desirable. It is strongly recommended that the Interconnection Customer obtain Company written approval before ordering protective equipment for parallel operation. The Interconnection Customer will own these protective measures installed at their facility.

(c) The Interconnection Customer shall obtain prior approval from the Company for any revisions to the specified relay calibrations.

C) Commissioning Testing

The following tests shall be completed by the Interconnection Customer. All of the required tests in each section shall be completed prior to moving on to the next section of tests. The Company Operator has the right to witness all field testing and to review all records prior to allowing the system to be made ready for normal operation. The Company shall be notified with sufficient lead time to allow the opportunity for Company personnel to witness any or all of the testing.

i) Pre-testing - The following tests are required to be completed on the Generation System prior to energization by the Generator or the Company. Some of these tests may be completed in the factory if no additional wiring or connections were made to that component. These tests are marked with a "*"

(1) Grounding shall be verified to ensure that it complies with this standard, the NESC, and the NEC.

(2) * CT's (Current Transformers) and VT's (Voltage Transformers) used for monitoring and protection, shall be tested to ensure correct polarity, ratio, and wiring

(3) CT's shall be visually inspected to ensure that all grounding and shorting connections have been removed, where required.

(4) Breaker / Switch tests – Verify that the breaker or switch cannot be operated with interlocks in place or that the breaker or switch cannot be automatically operated when in manual mode. Various Generation Systems have different interlocks, local or manual modes, etc. The intent of this section is to ensure that the breaker or switches controls are operating properly.

(5) * Relay Tests – All Protective relays shall be calibrated and tested to ensure the correct operation of the protective element. Documentation of all relay calibration tests and settings shall be furnished to the

Company Operator.

(6) Trip Checks - Protective relaying shall be functionally tested to ensure the correct operation of the complete system. Functional testing requires that the complete system is operated by the injection of current and/or voltage to trigger the relay element and proving that the relay element trips the required breaker, lockout relay, or provides the correct signal to the next control element. Trip circuits shall be proven through the entire scheme (including breaker trip)

For factory assembled systems, such as inverters, the setting of the protective elements may occur at the factory. This section requires that the complete system including the wiring and the device being tripped or activated is proven to be in working condition through the injection of current and/or voltage.

(7) Remote Control, SCADA, and Remote Monitoring tests -- All remote control functions and remote monitoring points shall be verified operational. In some cases, it may not be possible to verify all of the analog values before energization. Where appropriate, those points may be verified during the energization process.

(8) Phase Tests -- the Interconnection Customer shall work with the Company Operator to complete the phase test to ensure proper phase rotation of the Generation and wiring.

(9) Synchronizing test – The following tests shall be done across an open switch or racked out breaker. The switch or breaker shall be in a position that it is incapable of closing between the Generation System and the Company for this test. This test shall demonstrate that at the moment of the paralleling-device closure, the frequency, voltage, and phase angle are within the required ranges as stated in IEEE 1547 and 1547.1. This test shall also demonstrate that if any of the parameters are outside of the ranges stated, the paralleling-device shall not close. For inverter-based interconnected systems, this test may not be required unless the inverter creates fundamental voltages before the paralleling device is closed.

ii) <u>On-Line Commissioning Test</u> – the following tests will proceed once the Generation System has completed Pre-testing and the results have been reviewed and approved by the Company Operator. For 20 kW and under Generation Systems, the Company may waive joint interconnection tests. On larger and more complex Generation Systems, the Interconnection Customer and the Company Operator will get together to develop the required testing procedure. All on-line commissioning tests for larger facilities shall be based on written test procedures agreed to between the Company Operator and the Interconnection Customer.

Generation System functionally shall be verified for specific interconnections as follows:

(1) Anti-Islanding Test -- For Generation Systems that parallel with the utility for longer then 100 msec

(a) The Generation System shall be started and connected in parallel with the Company source.

(b) The Company source shall be removed by opening a switch, breaker, etc.

(c) The Generation System shall either separate with the local load or stop generating.

(d) The device that was opened to remove the Company source shall be closed and the Generation System shall not re-parallel with the Company for at least 5 minutes.

iii) <u>Final System Sign-off</u>

(1) To ensure the safety of the public, all interconnected customer owned generation systems which do not utilize a Type-Certified system shall be certified as ready to operate by a Professional Electrical Engineer registered in the State prior to the installation being considered ready for commercial use.

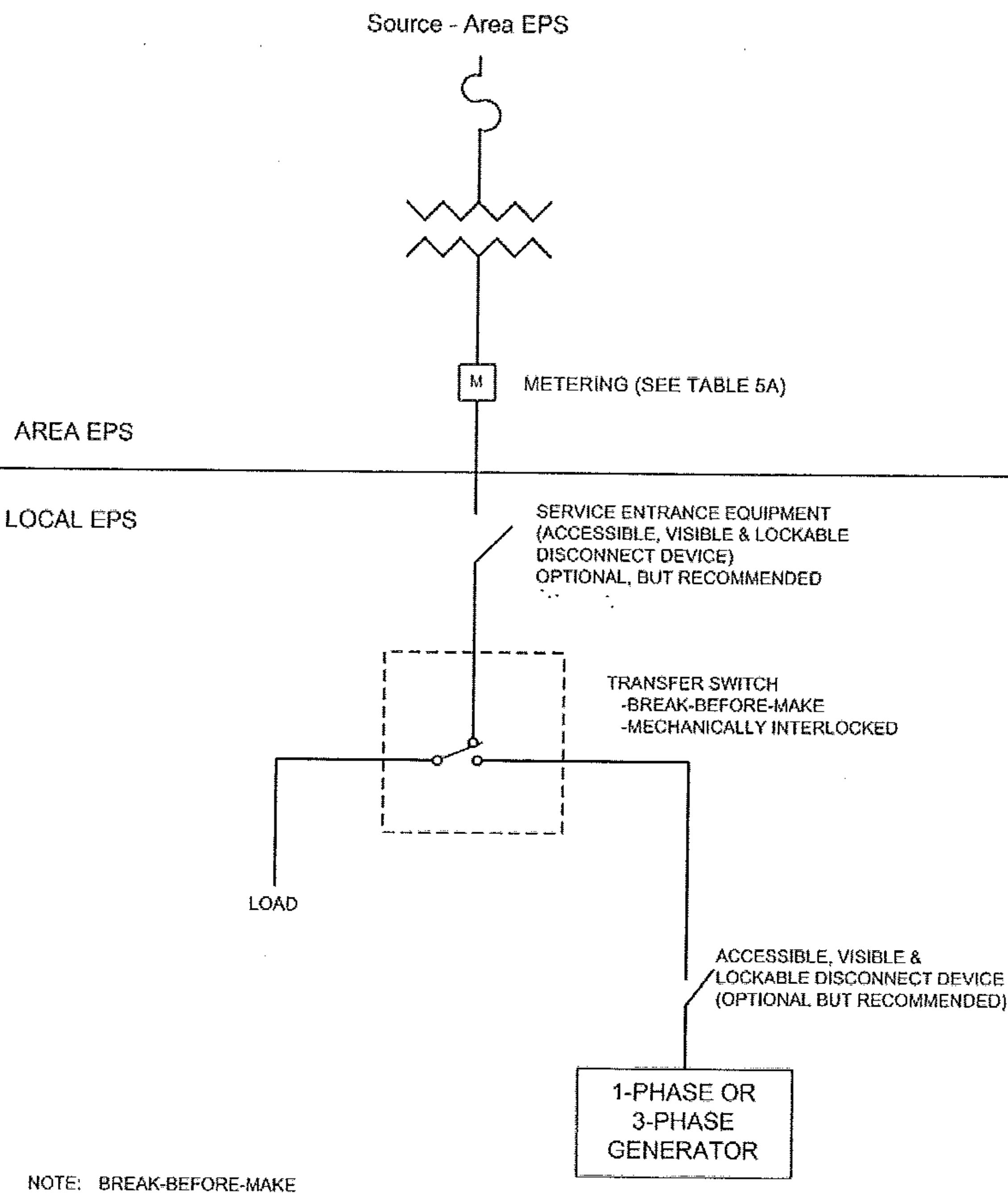
iv) Periodic Testing and Record Keeping

(1) Any time the interface hardware or software, including protective relaying and generation control systems are replaced and/or modified, the Company Operator shall be notified. This notification shall, if possible, be with sufficient warning so that the Company personnel can be involved in the planning for the modification and/or witness the verification testing. Verification testing shall be completed on the replaced and/or modified equipment and systems. The involvement of the Company personnel will depend upon the complexity of the Generation System and the component being replaced and/or modified. Since the Interconnection Customer and the Company Operator are now operating an interconnected system, it is important for each to communicate changes in operation, procedures, and/or equipment to ensure the safety and reliability of the Customer's and Company's systems.

(2) All interconnection-related protection systems shall be periodically tested and maintained by the Interconnection Customer at intervals specified by the manufacture or system integrator. These intervals shall not exceed 5 years. Periodic test reports and a log of inspections shall be maintained by the Interconnection Customer and made available to the Company Operator upon request. The Company Operator shall be notified before the periodic testing of the protective systems so that Company personnel may witness the testing if so desired. Testing notification for Facilities 20 kW and under is not required.

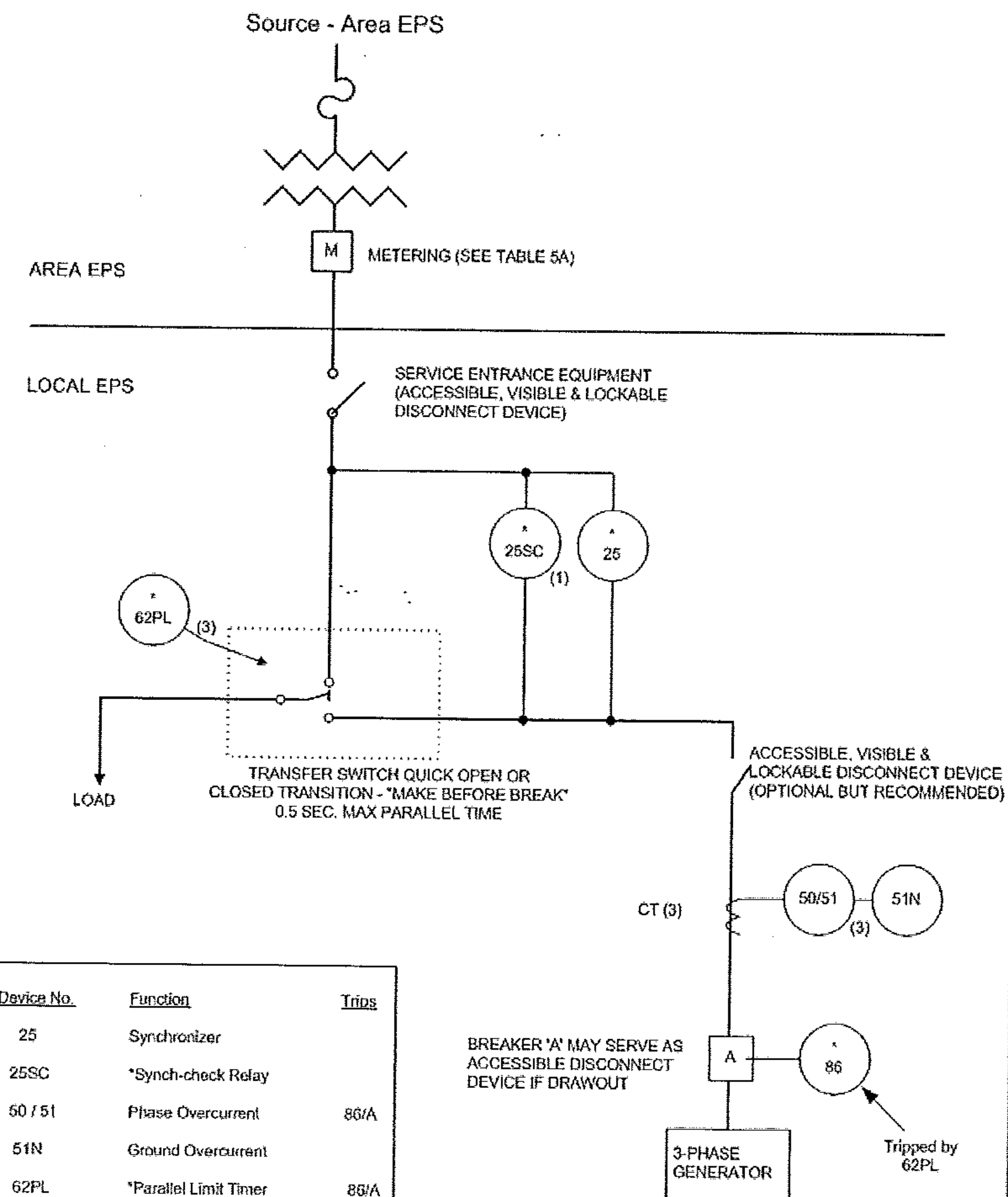
(a) Verification of inverter connected system rated 20 kW and below may be completed as follows: The Interconnection Customer shall operate the AC load break disconnect switch and verify the Generator automatically shuts down and does not restart for at least 5 minutes after the switch is closed.

(b) Any system that depends upon a battery for trip/protection power shall be checked and logged once per month for proper voltage. Once every four years, either the battery(s) must be replaced or a discharge test performed. Longer intervals are possible with "station class batteries" and Company Operator approval.



NOTE: BREAK-BEFORE-MAKE AUTOMATIC TRANSFER SWITCHES SHALL BE MECHANICALLY INTERLOCKED

OPEN TRANSITION "BREAK-BEFORE-MAKE"	
DATE: JAN 2003	Figure 1



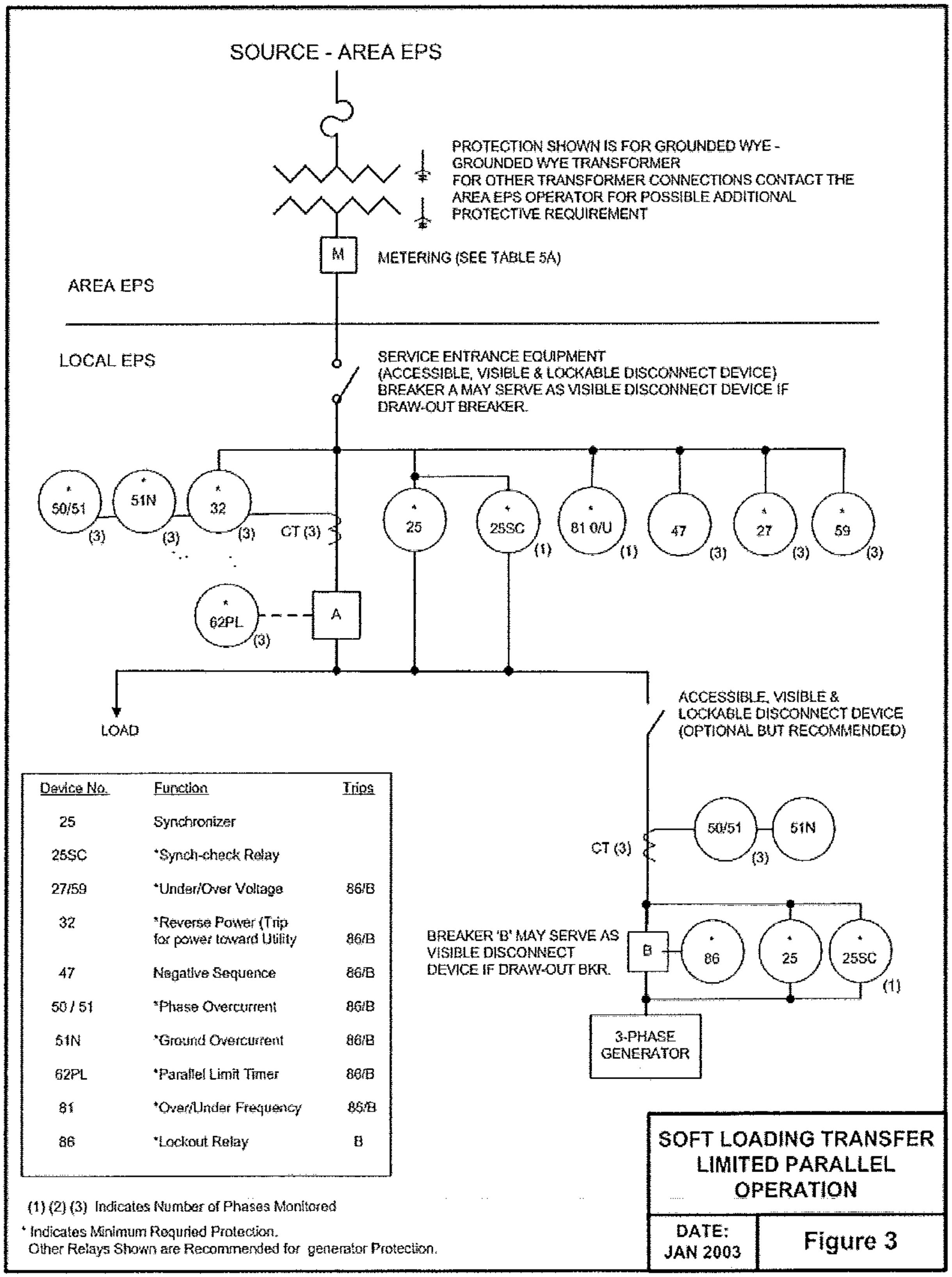
Device No.	Function	Trips
25	Synchronizer	
25SC	*Synch-check Relay	
50 / 51	Phase Overcurrent	86/A
51N	Ground Overcurrent	
62PL	*Parallel Limit Timer	86/A
86	*Lockout Relay	A

(1) (2) (3) Indicates Number of Phases to be Monitored
* Indicates Minimum Requried Protection
Other Relays Shown are Recommended for Generator Protection.

QUICK OPEN OR CLOSED TRANSITION "MAKE-BEFORE-BREAK"

DATE: JAN 2003

Figure 2



Device No.	Function	Trips
25	Synchronizer	
25SC	*Synch-check Relay	
27/59	*Under/Over Voltage	86/B
32	*Reverse Power (Trip for power toward Utility	86/B
47	Negative Sequence	86/B
50 / 51	*Phase Overcurrent	86/B
51N	*Ground Overcurrent	86/B
62PL	*Parallel Limit Timer	86/B
81	*Over/Under Frequency	86/B
86	*Lockout Relay	B

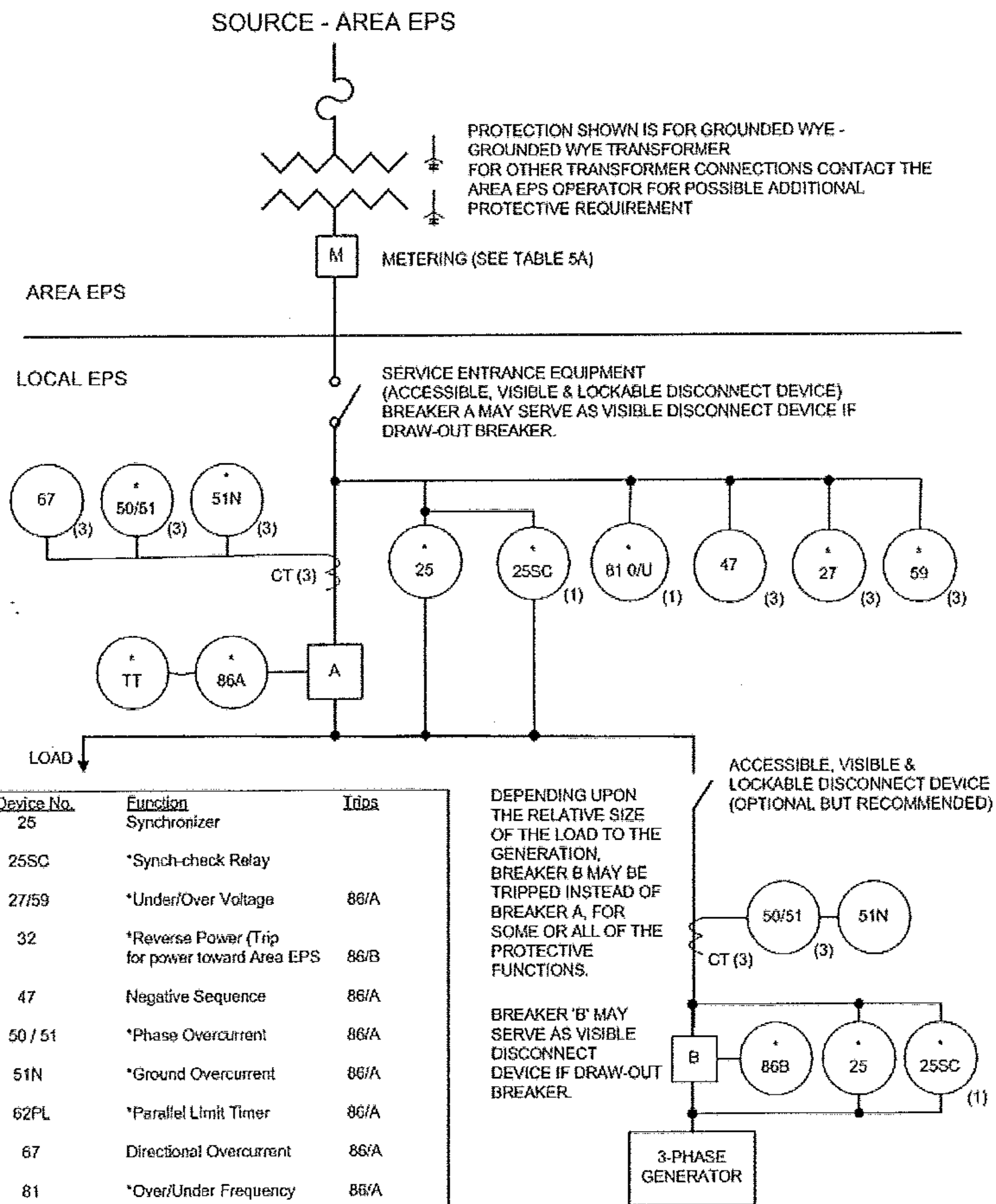
(1) (2) (3) Indicates Number of Phases Monitored

* Indicates Minimum Requried Protection.
Other Relays Shown are Recommended for generator Protection.

SOFT LOADING TRANSFER LIMITED PARALLEL OPERATION

DATE: JAN 2003

Figure 3



Device No.	Function	Trips
25	Synchronizer	
25SC	*Synch-check Relay	
27/59	*Under/Over Voltage	86/A
32	*Reverse Power (Trip for power toward Area EPS	86/B
47	Negative Sequence	86/A
50 / 51	*Phase Overcurrent	86/A
51N	*Ground Overcurrent	86/A
62PL	*Parallel Limit Timer	86/A
67	Directional Overcurrent	86/A
81	*Over/Under Frequency	86/A
86A	*Lockout Relay	A
86B	*Lockout Relay	B
TT	*Transfer Trip	86/A

TT is not required for Generation Systems smaller then 250kW

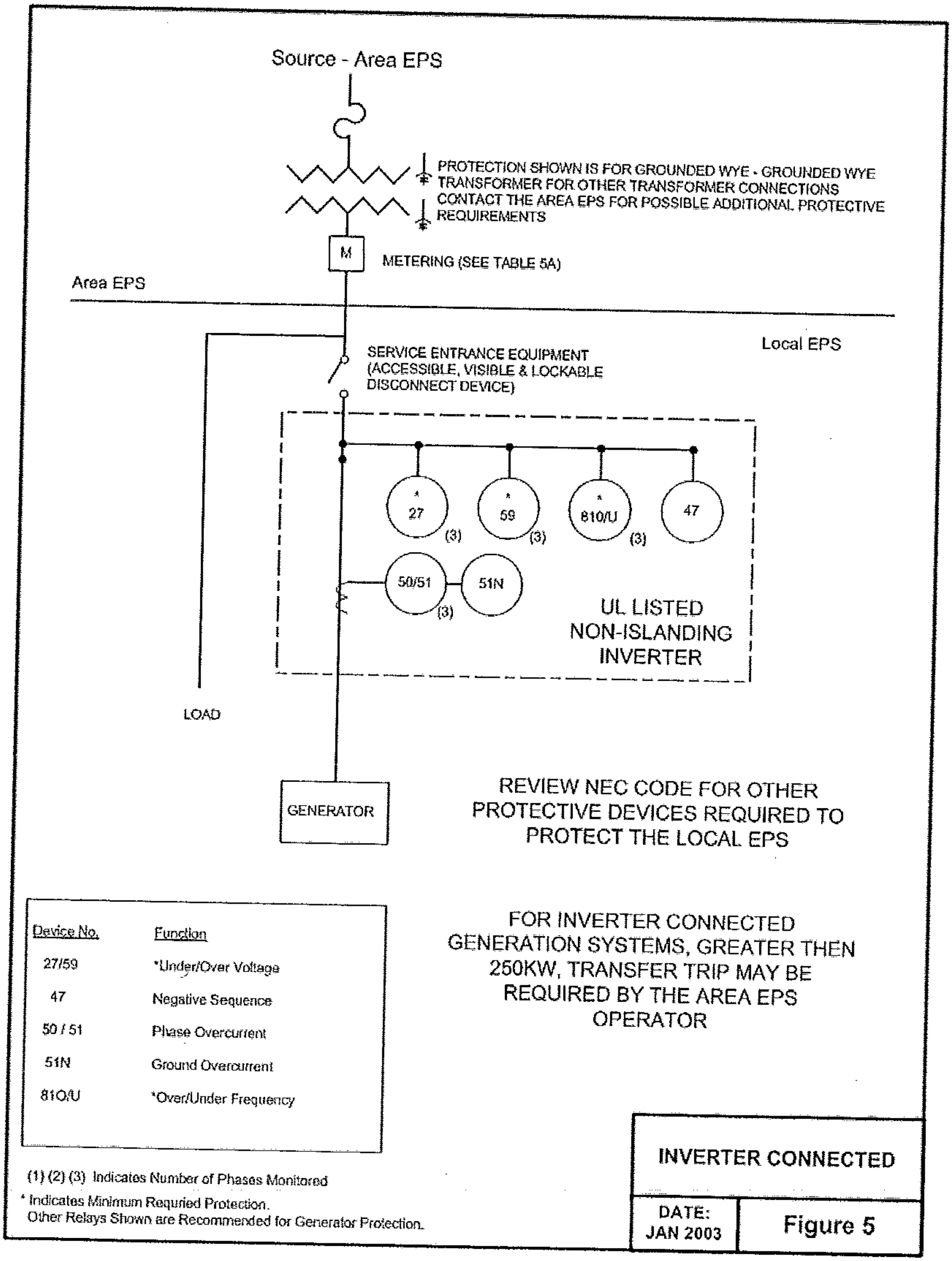
(1) (2) (3) Indicates Number of Phases Monitored

* Indicates Minimum Requried Protection.
Other Relays Shown are Recommended for generator Protection.

SOFT LOADING EXTENDED PARALLEL OPERATION

DATE: JAN 2003

Figure 4


Source - Area EPS
PROTECTION SHOWN IS FOR GROUNDED WYE - GROUNDED WYE TRANSFORMER FOR OTHER TRANSFORMER CONNECTIONS CONTACT THE AREA EPS FOR POSSIBLE ADDITIONAL PROTECTIVE REQUIREMENTS
M
METERING (SEE TABLE 5A)
Area EPS
Local EPS
SERVICE ENTRANCE EQUIPMENT (ACCESSIBLE, VISIBLE & LOCKABLE DISCONNECT DEVICE)
27
59
810/U
47
(3)
50/51
51N
UL LISTED NON-ISLANDING INVERTER
LOAD
GENERATOR
REVIEW NEC CODE FOR OTHER PROTECTIVE DEVICES REQUIRED TO PROTECT THE LOCAL EPS
FOR INVERTER CONNECTED GENERATION SYSTEMS, GREATER THEN 250KW, TRANSFER TRIP MAY BE REQUIRED BY THE AREA EPS OPERATOR
Device No. Function
27/59 *Under/Over Voltage
47 Negative Sequence
50 / 51 Phase Overcurrent
51N Ground Overcurrent
81O/U *Over/Under Frequency
(1) (2) (3) Indicates Number of Phases Monitored
* Indicates Minimum Requried Protection.
Other Relays Shown are Recommended for Generator Protection.
INVERTER CONNECTED
DATE: JAN 2003
Figure 5

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
General Rules & Regulations
Account History Charge Cost Analysis

Case No. PU-07-_______
Exhibit No.____(PJZ-1)
Schedule 8
Page 1 of 3

Account History Charge	
Section 3.10	
Description	**Minimum 10 Accounts**
Handling - printing	$ 32.27
Handling - stuffing envelopes	$ 6.45
Postage for histories	$ 0.99
Miscellaneous (paper, ink, etc.)	$ 0.02
Call Center labor cost per call	$ 2.75
Call Center IT costs per call	$ 0.36
Billing labor costs	$ 7.02
Producing bill	$ 0.10
Postage for bill	$ 0.28
Total Costs per request involving 10 accounts	**$ 50.24**
$/Account, minimum 10 accounts/request	**$ 5.02**

TARIFF	**Current Tariff Charge**	**2007 Costs**	**Proposed Tariff Charge**
Per account when the request involves 10 or more accounts	$ 0.50	**$ 5.02**	**$ 5.00**

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
General Rules & Regulations
Excess Footage Charge Analysis

Case No. PU-07-______
Exhibit No.____(PJZ-1)
Schedule 8
Page 2 of 3

Excess Footage Section 6.5.1.A1.				
Task	**Passport costs per circuit foot**	**Overhead**	**Overhead Costs**	**Proposed Tariff Charge per circuit foot**
Services	$ 5.35	28.13%	$1.50	**$6.85**

An analysis of projects was conducted using the Company's Passport System. Passport lists the field costs related to material, equipment, transportation, and labor costs of a construction project. The average cost for excess residential footage was $5.35 per circuit foot, less overhead.

The overhead rate of 28.13% applies for Engineering and Supervision costs associated with the construction project including labor costs for designers, engineers, and management. This is added to the Passport field cost, which results in $6.85 per circuit foot.

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Test Year Ending December 31, 2008
General Rules & Regulations
Winter Construction Charge Cost Analysis

Winter Construction Section 6.5.1.A.2		
	Proposed Tariff Charge	
Thawing	**$ 400.00**	**per frost burner**
Service, Primary, or Secondary distribution extension	**$ 3.00**	**per foot**

Frost burner	**# of Burners**	**Propane Costs**	**Average Propane $**	**Construction $**	**Average Construction $**	**Loading Factor**	**Cost/Burner**
Setting Tankers	103	$3,479.34	$33.78	$7,846.21	$76.18	$183.59	$217.37
Retanking Burners	111	$3,749.58	$33.78	$4,707.26	$42.41	$102.20	$135.98
Removing Burners	104	$0.00	$0.00	$7,714.72	$74.18	$178.77	$178.77
						241%	
					Adjusted cost/job		**$532.12**

Electric winter construction costs	**Estimated Actual Costs per Electric Job**	**Proposed Tariff Charge**
Service extension fixed $/job (or per frost burner)	$532.12	$ 400.00
Cost per Foot Trench	$ 3.00	$ 3.00
Average trench job of 40 foot	$ 120.00	$ 120.00
$/Second burner @ 10% of jobs	$ 53.21	$ 40.00
Call Center-Billing related tasks/job	$ 10.51	$ 10.51
Estimated Cost per job	**$ 718.84**	**$ 573.51**

The loading factor is the sum of overhead charges that pertain to the winter construction tasks relating to frost burners including: pension, insurance, taxes, workers compensation, non-productive time of vacation, sick leave, training, meetings, contract labor, etc. This applies only to Construction costs.