

July 31, 2012

VIA Electronic Filing

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Annual Informational Filing Regarding ISO Tariff Charges in Effect as of June 1, 2012, Pursuant to Docket Nos. RT04-2-000, *et al.*

Dear Secretary Bose:

The Participating Transmission Owners Administrative Committee (“PTO AC”) on behalf of New England’s Participating Transmission Owners (“PTOs”), hereby submits for informational purposes this letter and supporting materials that identify updated rates for regional transmission and scheduling, system control and dispatch services effective as of June 1, 2012 under Section II of the ISO New England Inc. Transmission, Markets and Services Tariff (“ISO Tariff”). The updated charges are based on actual cost data for calendar year 2011 and estimated cost data for calendar year 2012 pursuant to Commission-approved formula rates contained in Attachment F and Schedule 1 under Section II of the ISO Tariff.

I. Background

By order issued March 24, 2004 in Docket RT04-2-000, *et al.*, the Commission accepted the formation of the New England RTO (“March 24 Order”).¹ In its November 3, 2004 order in that proceeding, the Commission accepted a comprehensive settlement agreement, subject to conditions, that would terminate the existing Commission-approved NEPOOL Open Access Transmission Tariff and replace it with Section II of the ISO Tariff (“November 3 Order”).² In its February 10, 2005 order, the Commission approved the implementation of the New England RTO, including the ISO Tariff, effective as of February 1, 2005 (“February 10 Order”).³ Finally, on

¹ *ISO New England, Inc.*, 106 FERC ¶ 61,280 (2004).

² *ISO New England, Inc.*, 109 FERC ¶ 61,147 (2004).

³ *ISO New England, Inc.*, 110 FERC ¶ 61,111 (2005).

October 31, 2006 and on March 24, 2008, the Commission established the Return on Equity (“ROE”) used to calculate the applicable revenue requirements under Attachment F.⁴ Together, these orders are referred to as the “RTO Orders”.

Pursuant to the Commission’s RTO Orders and Attachment F of the ISO Tariff, the PTOs are responsible for making annual informational filings with the Commission to reflect the regional formula transmission rates.⁵ Attachment F makes clear that an informational filing “does not re-open the formula rate ...but rather is contestable only with respect to the accuracy of the information contained in the informational filing.” Also in accordance with Attachment F, a draft of the attached information was posted on the ISO website for stakeholder review no less than 45 days prior to this informational filing.

II. Charges Resulting from Annual Formula Rate Updates

Pursuant to Attachment F and Schedule 1 of the ISO Tariff, the PTOs are today submitting for informational purposes regional formula transmission charges for Regional Network Service (“RNS”), Through or Out (“TOUT”) Service, and Scheduling, System Control & Dispatch Service (Schedule 1) that will be in effect for the period beginning June 1, 2012 through May 31, 2013. In accordance with the Commission’s December 5, 2005 order accepting tariff revisions in Docket Nos. ER06-17-000 and EL05-56-000,⁶ and certain recent Commission orders,⁷ the enclosed filing includes forecasted revenue requirements associated with projected capital additions to Pool Transmission Facilities (“PTF”), the Maine Power Reliability Program Construction Work In Progress (“MPRP CWIP”), the New England East West Solution Construction Work In Progress (“NEEWS CWIP”), and a true-up of the amounts billed in the prior rate year.⁸ Specifically, the Attachment F formula rate incorporates forecasted revenue requirements for PTF capital additions expected to be placed in service on or before December 31, 2012 and forecasted MPRP and NEEWS CWIP as of December 31, 2012. It also incorporates a true-up, with interest computed in accordance with Part 35.19a of the Commission’s regulations (18 CFR 35.19a), representing the difference between the PTF revenue requirement based on 2010 actual data, plus 2011 forecasted data, and the revenue requirements for 2011 based on actual data.

Pursuant to Attachment F of the ISO Tariff, the annual formula rates have been updated to reflect actual 2011 cost data, Forecasted Transmission Revenue Requirements associated with projected PTF additions for 2012 (i.e. the Forecast Period), and the Annual True-up including

⁴ *Bangor Hydro-Electric Co., et al.*, Opinion No. 489, 117 FERC ¶ 61,129 (2006); *Order on rehearing*, 122 FERC ¶ 61,265 (2008).

⁵ The first such informational filing was submitted to the Commission by the PTOs on May 12, 2005 under Docket Nos. RT04-2-000, et al. for regional rates in effect as of February 1, 2005.

⁶ *ISO New England, Inc.* 113 FERC ¶ 61,243 (2005).

⁷ *Central Maine Power Company*, 128 FERC ¶ 61,143, *reh’g denied* 135 FERC ¶ 61, 139 (2011); *Northeast Utilities Service Company and National Grid USA*, 135 FERC ¶ 61,195 (2011). *The Connecticut Light and Power Company, Western Massachusetts Electric Company, and New England Power Company* FERC Docket Nos. ER12-1877-000 and ER12-1877-001, see Letter Order dated July 26, 2012 accepting additional modifications for NEEWS CWIP effective June 1, 2012.

⁸ This includes a true-up by Northeast Utilities and Vermont Transco of their PTF revenue requirements for prior years, to reflect the recent FERC orders in Docket Nos. FA11-15-000 and FA11-16-000, respectively.

associated interest. This annual update results in a Pool RNS Rate of \$75.25/kW-year effective June 1, 2012 through May 31, 2013. The new rate represents an increase of \$11.38 from the Pool RNS Rate of \$63.87/kW-year that went into effect on June 1, 2011. Attachments 3 and 4 provide a summary of the forecast and true-up related impacts on regional transmission charges. The annual update to the Schedule 1 formula rate results in a Schedule 1 charge of \$1.79/kW-year effective June 1, 2012. This represents an increase of \$0.21/kW-year over the Schedule 1 charge of \$1.58/kW-year based on 2010 data that went into effect as of June 1, 2011.

III. Attachments and Additional Supporting Information

The following supporting information has been provided and is enclosed herewith:

- This Transmittal Letter;
- Attachment 1 - Schedule 9 RNS Rates effective June 1, 2012 – May 31, 2013 based on 2011 actual data and 2012 forecasted data;
- Attachment 2 - PTOs' Annual Transmission Revenue Requirement calculations pursuant to Attachment F based on 2011 actual data and 2012 forecasted data (including Highgate Transmission Facilities ("HTF"));
- Attachment 3 – Summary of Forecasted Transmission Revenue Requirements associated with projected PTF additions and CWIP for MPRP and NEEWS for 2012;
- Attachment 4 – Annual True-up Summary;
- Attachment 5 - Schedule 1 Rates effective June 1, 2012 through May 31, 2013, based on 2011 data;
- Attachment 6 - PTOs' Annual Revenue Requirement calculations pursuant to Schedule 1, based on 2011 data;
- Attachment 7 - Service List of state regulators and other interested parties; and
- Attachment 8 - List of Participating Transmission Owners sponsoring this informational filing.

A copy of this submission is being sent to state regulators in New England, the New England Conference of Public Utility Commissioners ("NECPUC"), ISO New England Inc., NEPOOL and the Power Planning Committee of the New England Governors Conference, Inc. Attachment 7 identifies the service list of entities to whom this filing has been sent. In addition, Attachment 8 includes a service list of the PTOs making up the PTO AC and sponsoring this filing.

Thank you for your attention to this matter. Please contact me if you have any questions concerning this informational filing.

Respectfully submitted,

/s/ Michael J. Hall

Michael J. Hall, Esq.
Counsel to Northeast Utilities
& Chair of the PTO AC Legal Working Group
On behalf of the Participating Transmission Owners
Administrative Committee

Attachments

cc: Persons and Entities identified in Attachments 7 and 8.

Attachment 1

**Schedule 9 RNS Rates Effective June 1, 2012 – May 31, 2013
Based on 2011 Actual Data, 2012 Forecasted Data and Annual True-up**

PTO 2011 12 CP NETWORK LOADS

	2011
Local Networks	Network Load (MW)
NSTAR	4,183.764
Bangor Hydro Electric	250.636
Fitchburg Gas & Electric	76.933
Central Maine Power	1,365.741
National Grid	5,763.438
Northeast Utilities	6,992.357
United Illuminating	724.457
VTransco	821.017
Total	20,178.343

Long Term TOUT (MW)	0

PTO RNS Rates for 6/1/12	PRE 97 RNS Rate	Post 96 RNS Rate	RNS Rates for June 1, 2012 (Revised on 6/15/12)	RNS Rates previously in effect June 1, 2011	Delta
Total NE Rev Req	\$293,446,447	\$1,225,071,781			
Total NE Loads - kw	20,178,343	20,178,343			
Total NE RNS \$ / kw-yr.	14.54264	60.71221	75.25485	63.87374	11.38111

		PTO 2011 Rev Req						
		PTO Annual Input Data 2011- (Revised on 6/15/12)						
					PTF Revenue Requirements			
					Pre-1997	Post-1996		
		Customer #	DUNS #	DUNS Name	PTF	PTF		
					\$	\$		
1	*	1	83-729-7852	Ashburnham Municipal Light Dept.	\$ 6,354	\$ -	1	
2		2	00-694-9002	Bangor Hydro Transmission	\$ 792,877	\$ 46,979,915	2	
3	*	4	06-991-6021	Boylston Municipal Light Dept.	\$ 7,542	\$ -	3	
4		5	17-057-1897	Braintree Electric Light Dept.	\$ 217,494	\$ 2,079,295	4	
5		6	00-694-8954	Central Maine Power Transmission	\$ 14,050,884	\$ 133,171,791	5	
6	*	7	11-468-3899	Chicopee Municipal Lighting Plant	\$ 30,800	\$ -	6	
7	*	90	07-952-6729	Concord Municipal Light Dept.	\$ 11,733	\$ -	7	
8		8	09-207-8351	Conn Municipal Electric Energy Coop.	\$ 416,471	\$ 1,211,022	8	
9		51386	96-733-8696	Connecticut Transmission Municipal Electric	\$ -	\$ 7,177,448	9	
10	*	9	15-596-9157	Danvers Electric Dept.	\$ 92,942	\$ -	10	
11	*	39	15-596-9983	Georgetown Municipal Light Dept.	\$ 8,178	\$ -	11	
12	*	40	15-601-8301	Groton Electric Light Dept.	\$ 10,460	\$ -	12	
13		38	00-695-4317	Fitchburg Gas & Electric Light Co.	\$ 244,530	\$ 598,029	13	
14	*	42	14-703-0704	Hingham Municipal Lighting Plant	\$ 40,985	\$ -	14	
15	*	43	87-808-0563	Holden Municipal Light Dept.	\$ 31,274	\$ -	15	
16		44	08-465-0050	Holyoke Gas & Electric Dept.	\$ 1,177,080	\$ 1,615,403	16	
17		45	10-775-5126	Hudson Light & Power Dept.	\$ 109,161	\$ -	17	
18	*	72	13-661-7156	Hull Municipal Lighting Plant	\$ 13,901	\$ -	18	
19	*	73	15-586-9563	Ipswich Municipal Light Dept.	\$ 7,918	\$ -	19	
20	*	75	79-432-5019	Littleton Electric Light & Water Dept.	\$ 15,163	\$ -	20	
21		6	06-099-4258	Maine Electric Power Company	\$ (1,096,825)	\$ (250,713)	21	
22	*	77	95-690-6051	Mansfield Municipal Electric Dept.	\$ 64,749	\$ -	22	
23	*	78	15-598-9544	Marblehead Municipal Light Dept.	\$ 21,348	\$ -	23	
24	*	79	15-597-6665	Middleborough Gas & Electric Dept.	\$ 609,413	\$ 424,700	24	
25	*	80	18-675-8231	Middleton Municipal Electric Dept.	\$ 23,988	\$ -	25	
26		81	00-695-2881	National Grid	\$ 109,429,967	\$ 164,091,494	26	
27		51321	83-132-2677	New Hampshire Transmission, LLC	\$ 3,230,069	\$ 6,948,525	27	
28	*	111	10-798-9241	North Attleboro Electric Dept.	\$ 37,421	\$ -	28	
29		112	95-910-8929	Northeast Utilities Transmission	\$ 77,771,290	\$ 523,580,986	29	
30		158	08-421-1572	Norwood Municipal Light Plant	\$ -	\$ 2,742,505	30	
31		3	00-695-1552	NSTAR	\$ 51,405,632	\$ 121,527,590	31	
32	*	116	06-984-9461	Pascoag Fire District - Electric Dept	\$ 8,027	\$ -	32	
33	*	117	15-582-5391	Paxton Municipal Light Department	\$ 7,241	\$ -	33	
34	*	144	10-371-6353	Peabody Municipal Light Plant	\$ 99,435	\$ -	34	
35		148	86-703-4654	Reading Municipal Light Dept.	\$ (51,642)	\$ 298,098	35	
36	*	146	11-885-5188	Rowley Municipal Lighting Plant	\$ 1,540	\$ -	36	
37	*	149	78-451-8870	Shrewsbury Electric Light Plant	\$ 55,571	\$ -	37	
38	*	152	15-586-0620	Sterling Municipal Electric Light Dept.	\$ 12,104	\$ -	38	
39	*	150	19-548-8630	South Hadley Electric Light Dept.	\$ 50,157	\$ -	39	
40		153	04-661-6033	Taunton Municipal Lighting Plant	\$ 348,980	\$ -	40	
41	*	180	02-619-2302	Templeton Municipal Lighting Plant	\$ 18,252	\$ -	41	
42	*	185	79-806-8342	Unitil Power Corp	\$ 120,549	\$ -	42	
43		181	00-691-7967	The United Illuminating Company	\$ 21,498,198	\$ 92,855,464	43	
44		50853	78-039-9163	Vermont Trans	\$ 12,352,245	\$ 114,823,981	44	
45		182	00-579-1934	Vermont Electric Power Co, Inc.	\$ -	\$ 5,196,248	45	
46	*	183	15-415-7622	Wakefield Municipal Light Dept	\$ 40,834	\$ -	46	
47	*	186	12-787-0350	West Boylston Municipal Light Plant	\$ 17,609	\$ -	47	
48	*	187	12-757-5165	Westfield Gas & Electric Light Dept.	\$ 84,548	\$ -	48	
49				Total	\$ 293,446,447	\$ 1,225,071,781	49	
	*	Revenue requirement amounts indicate payments made to support PTF owned by other Participants.						

					LOAD VALUE (kW)													
					Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Total Annual Network Load	Average Monthly Network Load
Total Local Network Load (kW):					20,763,482	19,626,032	18,399,242	16,375,809	19,590,957	23,056,554	27,380,018	23,270,416	20,021,895	17,182,931	17,482,607	18,990,122	242,140,065	20,178,343
Local Network ID	Local Network Name																	
1	BE				4,207,369	3,992,675	3,743,125	3,368,598	4,036,469	4,824,477	5,829,009	4,986,660	4,349,628	3,563,134	3,520,025	3,783,987	50,205,156	4,183,764
2	BHE				275,035	265,721	242,294	224,301	226,634	240,440	295,125	266,820	245,236	230,237	238,919	256,873	3,007,635	250,636
4	CMP				1,431,866	1,361,537	1,297,310	1,300,660	1,238,375	1,360,303	1,633,260	1,410,910	1,312,310	1,327,310	1,303,540	1,411,510	16,388,891	1,365,741
6	NEP				5,925,622	5,594,450	5,251,126	4,608,774	5,486,819	6,624,211	7,933,061	6,747,231	5,739,226	4,813,389	4,996,836	5,440,407	69,161,252	5,763,438
7	NU				7,277,837	6,827,031	6,343,880	5,518,947	7,042,855	8,213,832	9,600,202	8,031,729	6,768,028	5,814,378	5,956,937	6,512,611	83,908,267	6,992,357
8	UI				686,663	672,274	640,969	553,526	714,247	869,980	1,048,281	890,372	771,519	603,440	601,944	640,266	6,693,481	724,457
9	VELCO/VT Transco				877,117	835,249	806,423	732,667	771,165	837,636	946,661	852,530	760,979	764,040	796,730	870,985	9,852,182	821,017
15	FGE				81,973	77,095	74,115	68,336	74,293	85,675	94,419	84,164	74,969	67,003	67,676	73,483	923,201	76,933
Total Network Load (kW)					20,763,482	19,626,032	18,399,242	16,375,809	19,590,957	23,056,554	27,380,018	23,270,416	20,021,895	17,182,931	17,482,607	18,990,122	242,140,065	20,178,343
Local Network ID	Local Network Name	Network Load ID	Duns Number	Network Load Name	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Total Annual Network Load	Average Monthly Network Load
1	BE	2	17-057-1897	Braintree	66,081	61,524	58,765	49,837	64,691	77,263	89,601	78,798	66,230	53,151	55,767	61,126	782,834	65,236
1	BE	4	07-952-6729	Concord	32,640	31,645	29,218	25,343	32,484	39,098	45,920	37,487	33,137	25,336	27,302	29,403	389,013	32,418
1	BE	5	14-703-0704	Hingham	34,080	32,196	31,048	26,140	37,432	46,404	56,560	45,404	39,592	30,104	31,076	33,288	443,324	36,944
1	BE	6	13-661-7155	Hull	9,987	9,565	8,722	5,435	7,270	10,240	14,584	10,120					75,923	6,327
1	BE	6	13-661-7156	Hull									8,260	8,054	8,800	8,880	33,994	2,833
1	BE	8	08-421-1572	Norwood (NYPA)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	BE	9	08-421-1572	Norwood (NU)	53,640	49,770	47,970	45,135	57,465	68,310	79,155	69,390	59,175	44,748	43,332	49,260	667,350	55,613
1	BE	11	00-695-2626	MECO - Quincy/Wey. (R W)	222,502	206,746	196,597	143,348	191,467	233,709	288,586	240,543	201,157	174,061	181,755	194,648	2,475,119	206,260
1	BE	13	86-703-4654	Reading	78,684	75,348	73,356	69,060	84,684	101,028	113,256	102,660	92,332	72,132	68,580	74,880	1,006,000	83,833
1	BE	14	17-819-3330	Wellseley	45,691	43,722	38,955	33,958	46,720	55,909	66,280	52,758	46,839	35,546	39,050	40,777	546,205	45,517
1	BE	15	07-382-0680	Belmont (PASNY)	24,013	23,565	21,757	15,805	21,649	27,275	32,563	25,763	22,164	18,923	20,990	22,238	276,705	23,059
2	BHE	16	00-694-9002	Bangor Hydro Electric	268,940	259,568	236,858	220,103	222,682	236,205	289,023	262,431	241,119	225,827	233,218	250,870	2,946,844	245,570
2	BHE	17	00-694-8954	CMP - Herman Sub	6,095	6,153	5,436	4,198	3,952	4,235	6,102	4,389	4,117	4,410	5,701	6,003	60,791	5,066
4	CMP	21	00-694-8954	Central Maine Power	1,393,739	1,314,320	1,256,723	1,261,789	1,189,830	1,314,292	1,586,417	1,355,581	1,260,884	1,272,624	1,261,450	1,357,663	15,825,312	1,318,776
4	CMP	22	11-923-4722	NP - Fox Island	1,830	1,514	1,455	1,225	1,323	1,064	1,750	1,770	1,940	1,560	1,480	1,730	18,641	1,553
4	CMP	23	05-448-1341	NP - Kennebunk	18,263	17,426	15,961	14,952	14,028	16,815	21,410	16,830	15,600	14,570	15,820	17,110	198,785	16,565
4	CMP	24	61-283-4382	Madison Paper	9,978	20,556	16,308	16,164	27,228	21,738	16,400	31,920	29,390	34,020	19,470	29,240	272,412	22,701
6	NEP	31	00-695-2881	New England Power	163	159	162	132	54	70	43	53	20	71	120	132	1,179	98
6	NEP	32	00-695-2261	Granite St. Elec. (R W)	152,389	145,121	138,280	124,636	155,533	157,665	200,054	183,739	150,623	128,564	130,994	143,336	1,810,934	150,911
6	NEP	34	00-119-3655	Narragansett Electric	1,308,277	1,249,373	1,171,010	1,027,215	1,275,426	1,514,589	1,914,389	1,652,796	1,374,106	1,087,181	1,124,718	1,244,155	15,943,235	1,328,603
6	NEP	35	83-729-7852	Ashburnham	6,667	6,376	5,729	5,284	4,816	5,019	6,527	5,436	4,299	5,651	5,632	6,053	67,489	5,624
6	NEP	36	00-695-1552	Boston Edison Co.	47,056	47,138	45,019	42,396	53,258	55,543	63,187	55,341	50,183	43,118	44,413	46,974	593,626	49,469
6	NEP	37	06-991-6021	Boylston									4,576	4,647	5,060	5,494	19,777	1,648
6	NEP	37	XX-040-0000	Boylston	5,957	5,655	5,161	4,445	4,939	5,977	7,338	5,514					44,986	3,749
6	NEP	38	96-258-1922	VELCO - Central Vt Pub. Ser.	10,491	9,725	9,194	8,119	7,488	7,797	10,380	16,817	6,769	7,354	7,745	8,186	110,065	9,172
6	NEP	39	15-596-9157	Danvers	57,226	53,770	50,890	42,077	51,149	69,811	80,294	66,384	60,711	44,611	47,577	50,861	675,361	56,280
6	NEP	41	00-695-6551	NU - French King	10,048	10,394	9,563	8,365	7,613	7,962	9,816	8,612	6,568	8,470	9,211	9,394	106,016	8,835
6	NEP	42	15-596-9983	Georgetown	9,693	9,067	8,389	7,332	7,960	11,206	13,333	11,067	8,840	7,604	6,794	9,066	110,351	9,196

					LOAD VALUE (kW)													
					Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Total Annual Network Load	Average Monthly Network Load
Total Local Network Load (kW):					20,763,482	19,626,032	18,399,242	16,375,809	19,590,957	23,056,554	27,380,018	23,270,416	20,021,895	17,182,931	17,482,607	18,990,122	242,140,065	20,178,343
Local Network ID	Local Network Name																	
1	BE				4,207,369	3,992,675	3,743,125	3,368,598	4,036,469	4,824,477	5,829,009	4,986,660	4,349,628	3,563,134	3,520,025	3,783,987	50,205,156	4,183,764
2	BHE				275,035	265,721	242,294	224,301	226,634	240,440	295,125	266,820	245,236	230,237	238,919	256,873	3,007,635	250,636
4	CMP				1,431,866	1,361,537	1,297,310	1,300,660	1,238,375	1,360,303	1,633,260	1,410,910	1,312,310	1,327,310	1,303,540	1,411,510	16,388,891	1,365,741
6	NEP				5,925,622	5,594,450	5,251,126	4,608,774	5,486,919	6,624,211	7,933,061	6,747,231	5,739,226	4,813,389	4,996,836	5,440,407	69,161,252	5,763,438
7	NU				7,277,837	6,827,031	6,343,880	5,518,947	7,042,855	8,213,832	9,600,202	8,031,729	6,768,028	5,814,378	5,956,937	6,512,611	83,908,267	6,992,357
8	UI				686,663	672,274	640,969	553,526	714,247	869,980	1,048,281	890,372	771,519	603,440	601,944	640,266	6,693,481	724,457
9	VELCO/VT Transco				877,117	835,249	806,423	732,667	771,165	837,636	946,661	852,530	760,979	764,040	796,730	870,985	9,852,182	821,017
15	FGE				81,973	77,095	74,115	68,336	74,293	85,675	94,419	84,164	74,969	67,003	67,676	73,483	923,201	76,933
Total Network Load (kW)					20,763,482	19,626,032	18,399,242	16,375,809	19,590,957	23,056,554	27,380,018	23,270,416	20,021,895	17,182,931	17,482,607	18,990,122	242,140,065	20,178,343
Local Network ID	Local Network Name	Network Load ID	Duns Number	Network Load Name	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Total Annual Network Load	Average Monthly Network Load
6	NEP	44	15-601-8301	Groton MA	14,016	11,641	10,248	9,163	11,332	14,668	18,532	13,966	12,158	10,192	9,869	11,388	147,173	12,264
6	NEP	45	15-601-8285	NP - Groveland	7,664	7,457	5,989	5,319	5,802	8,353	10,343	8,077	6,413	5,527	5,999	6,531	83,474	6,956
6	NEP	46	87-808-0563	Holden	19,483	18,673	17,296	14,509	15,290	18,757	21,519	17,522	14,807	16,014	17,476	18,399	209,745	17,479
6	NEP	47	10-775-5126	Hudson	58,156	56,084	53,452	48,468	59,276	68,292	75,348	65,524	58,912	47,824	50,204	52,612	694,152	57,846
6	NEP	48	15-586-9563	Ipswich	20,357	19,495	17,991	15,477	16,903	23,646	28,652	23,809	19,584	17,051	17,484	19,198	239,647	19,971
6	NEP	49	79-432-5019	Littleton MA	42,007	42,008	38,431	35,804	46,154	50,354	52,150	48,263	43,718	36,893	39,053	39,866	514,701	42,892
6	NEP	50	09-551-3214	NP - Littleton NH	12,545	11,962	11,591	10,193	10,469	11,210	14,040	12,725	10,400	10,657	11,191	12,140	139,123	11,594
6	NEP	51	95-690-6051	Mansfield	39,557	37,411	33,984	31,162	40,449	47,131	55,685	48,413	39,369	30,499	31,896	35,726	471,282	39,274
6	NEP	53	15-598-9544	Marblehead	22,350	20,853	18,801	16,542	14,274	22,167	30,717	20,988	17,730	17,793	18,909	19,602	240,726	20,061
6	NEP	54	92-933-1452	Massachusetts Development Fin	24,707	24,570	24,344	17,413	19,926	22,616	22,635	21,616	20,093	15,548	15,117	15,460	244,045	20,337
6	NEP	55	78-609-1892	NP - Merrimac	5,981	5,676	5,093	4,472	4,358	6,379	8,294	6,244	4,768	4,816	5,100	5,651	66,832	5,569
6	NEP	56	18-675-8231	Middleton	16,727	15,863	15,033	12,925	15,898	20,892	24,624	20,581	17,314	13,271	13,893	15,327	202,348	16,862
6	NEP	57	10-798-9241	N. Attleboro									41,552	34,656	36,928	40,208	153,344	12,779
6	NEP	57	13-938-4465	N. Attleboro	45,168	41,872	39,136	33,328	40,848	48,512	58,944	51,376					359,184	29,932
6	NEP	60	15-582-5391	Paxton	4,786	4,594	4,164	3,952	3,444	3,881	4,859	3,745	3,285	4,101	4,380	4,653	49,844	4,154
6	NEP	61	10-371-6353	Peabody	89,000	83,200	77,400	66,600	79,500	106,600	128,900	104,100	92,600	69,400	73,200	78,600	1,049,100	87,425
6	NEP	62	96-152-2786	NP - Princeton	3,616	3,324	3,043	2,616	1,512	1,875	3,241	2,420	2,080	2,789	3,228	3,190	32,934	2,745
6	NEP	63	11-885-5188	Rowley	7,877	7,578	6,961	5,924	6,910	9,891	11,916	9,741	7,708	6,321	6,748	7,510	95,085	7,924
6	NEP	64	78-451-8870	Shrewsbury	53,397	50,922	46,955	40,291	49,471	56,145	65,923	52,027	45,951	42,718	44,723	48,503	597,026	49,752
6	NEP	65	15-586-0620	Sterling	9,855	9,336	9,034	7,838	9,582	10,630	11,975	10,795	9,307	8,677	8,776	9,958	115,763	9,647
6	NEP	66	02-619-2302	Templeton	10,493	9,989	9,294	7,368	7,510	9,037	10,037	8,735	7,666	8,777	8,334	10,193	107,433	8,953
6	NEP	67	15-415-7622	Wakefield	33,583	32,559	29,787	26,494	30,391	41,009	49,375	40,001	34,574	27,938	30,039	31,786	407,536	33,961
6	NEP	68	12-787-0350	W. Boylston	10,332	9,798	9,435	7,933	9,253	11,068	12,792	10,392	8,880	8,407	9,001	9,546	116,837	9,736
7	NU	70	00-694-8954	CMP - Bolt Hill	41,539	44,691	42,545	37,871	35,165	36,710	51,501	48,552	40,737	38,794	39,651	32,240	489,996	40,833
7	NU	71	11-468-3899	Chicopee	81,126	74,097	70,301	60,443	77,501	89,101	97,920	86,053	71,548	62,048	63,952	72,786	906,876	75,573
7	NU	72	96-165-7079	Conn. Mun. Elec. Enr. Co	258,331	231,535	223,068	204,872	250,170								1,167,976	97,331
7	NU	72	96-773-8696	Conn. Mun. Elec. Enr. Co						300,798	326,728	293,197	263,141	197,542	204,079	223,451	1,808,936	150,745
7	NU	73	08-465-0050	Holyoke	61,900	55,677	53,904	50,458	61,139	69,922	74,471	69,275	60,380	49,856	48,980	55,202	711,164	59,264

					LOAD VALUE (kW)													
					Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Total Annual Network Load	Average Monthly Network Load
Total Local Network Load (kW):					20,763,482	19,626,032	18,399,242	16,375,809	19,590,957	23,056,554	27,380,018	23,270,416	20,021,895	17,182,931	17,482,607	18,990,122	242,140,065	20,178,343
Local Network ID	Local Network Name																	
1	BE				4,207,369	3,992,675	3,743,125	3,368,598	4,036,469	4,824,477	5,829,009	4,986,660	4,349,628	3,563,134	3,520,025	3,783,987	50,205,156	4,183,764
2	BHE				275,035	265,721	242,294	224,301	226,634	240,440	295,125	266,820	245,236	230,237	238,919	256,873	3,007,635	250,636
4	CMP				1,431,866	1,361,537	1,297,310	1,300,660	1,238,375	1,360,303	1,633,260	1,410,910	1,312,310	1,327,310	1,303,540	1,411,510	16,388,891	1,365,741
6	NEP				5,925,622	5,594,450	5,251,126	4,608,774	5,486,819	6,624,211	7,933,061	6,747,231	5,739,226	4,813,389	4,996,836	5,440,407	69,161,252	5,763,438
7	NU				7,277,837	6,827,031	6,343,880	5,518,947	7,042,855	8,213,832	9,600,202	8,031,729	6,768,028	5,814,378	5,956,937	6,512,611	83,908,267	6,992,357
8	UI				686,663	672,274	640,969	553,526	714,247	869,980	1,048,281	890,372	771,519	603,440	601,944	640,266	8,693,481	724,457
9	VELCO/VT Transco				877,117	835,249	806,423	732,667	771,165	837,636	946,661	852,530	760,979	764,040	796,730	870,985	9,852,182	821,017
15	FGE				81,973	77,095	74,115	68,336	74,293	85,675	94,419	84,164	74,969	67,003	67,676	73,483	923,201	76,933
Total Network Load (kW)					20,763,482	19,626,032	18,399,242	16,375,809	19,590,957	23,056,554	27,380,018	23,270,416	20,021,895	17,182,931	17,482,607	18,990,122	242,140,065	20,178,343
Local Network ID	Local Network Name	Network Load ID	Duns Number	Network Load Name	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Total Annual Network Load	Average Monthly Network Load
7	NU	74	00-695-2626	Mass Elec - SBNG (R W)	99,666	89,406	83,171	69,176	89,531	96,505	119,902	97,303	79,284	77,049	78,137	82,554	1,061,684	88,474
7	NU	76	19-548-8630	S.Hadley	21,414	20,829	18,619	15,245	21,319	24,776	27,355	23,380	19,062	17,533	17,533	19,550	246,615	20,551
7	NU	77	00-691-7967	UI S/S	225,325	214,716	200,131	166,868	238,253	298,538	348,853	268,892	224,256	169,251	178,436	192,155	2,725,674	227,140
7	NU	79	12-757-5165	NP - Chester	1,107	1,044	954	749	640	761	951	784	603	862	895	1,018	10,368	864
7	NU	80	12-757-5165	Westfield	61,593	60,369	55,985	50,077	67,759	76,029	81,968	75,483	62,848	54,868	54,019	59,786	760,784	63,399
8	UI	81	00-691-7967	United Illuminating	680,505	662,724	631,624	545,724	706,091	867,786	1,027,654	888,545	763,006	599,719	584,537	630,796	8,588,711	715,726
9	VELCO/VT Transco	82	00-579-1934	Vermont Electric Power Co	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	NU	83	00-881-9492	NHEC	140,302	128,049	121,902	96,132	98,348	110,274	152,507	121,768	93,671	104,453	122,100	141,804	1,431,310	119,276
8	UI	84	00-691-7090	NU-Branford Railroad 48R Substation	2,258	3,214	2,433	2,618	3,260	2,194	2,771	1,827	2,609	967	3,151	3,134	30,436	2,536
6	NEP	85	00-881-9492	New Hampshire Electric Co op	2,092	1,894	1,788	1,689	1,199	1,189	1,712	1,395	1,088	1,566	1,644	1,804	19,060	1,588
4	CMP	89	84-173-9824	NP - Gates Formed Fibre	1,942	1,801	1,659	1,700	1,841	1,736	2,000						12,679	1,057
6	NEP	91	86-703-4654	North Reading	34,055	32,846	29,728	26,763	34,844	47,363	57,610	40,925	33,768	27,670	30,429	33,743	429,744	35,812
7	NU	94	00-697-1352	Citizens Utilites	232	197	202	140	138	142	171	156	125	176	213	249	2,141	178
7	NU	95	11-923-4722	Ashland	3,607	3,261	3,292	2,751	2,298	2,573	3,543	3,081	2,176	2,745	2,691	3,004	35,022	2,919
7	NU	96	11-923-4722	New Hampton	574	565	486	435	392	402	511	448	431	492	425	531	5,692	474
4	CMP	97	05-448-1341	FPL Energy	57	46	66	0	0	9	73	99	16	16	0	47	429	36
6	NEP	98	04-661-6033	Taunton	118,780	109,020	104,300	93,480	114,580	132,640	157,690	140,876	117,120	92,710	97,660	105,730	1,384,586	115,382
6	NEP	99	00-176-6260	NP - MBTA - EUA	456	448	227	184	39	38	40	37	36	200	214	231	2,150	179
6	NEP	100	15-597-6665	Middleboro	42,400	39,056	36,762	33,149	40,569	49,372	63,212	53,747	43,794	37,803	37,955	41,701	519,520	43,293
6	NEP	101	06-984-9461	Pascoag	10,002	9,958	8,651	7,910	8,609	10,241	12,765	10,786	8,679	8,539	9,048	9,874	115,062	9,589
6	NEP	102	00-697-1352	Public Service of NH	2,535	0	0	0	0	0	0	0	0	0	0	0	2,535	211
6	NEP	103	01-821-3640	ANP Bellingham	2,156	1,614	2,155	0	0	0	0	0	0	1,000	2,000	1,000	9,925	827
4	CMP	105	16-966-8212	Westbrook Energy Center	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	UI	106	84-878-4257	PSEG - Energy Resources & Trading, LLC	0	6,336	6,912	5,184	4,896	0	17,856	0	5,904	2,304	14,256	6,336	69,984	5,832
7	NU	108	00-378-9070	Unitil Energy Systems Inc.	214,510	203,905	189,434	168,641	197,192	225,894	297,615	234,704	202,976	176,331	182,403	199,639	2,493,244	207,770
4	CMP	111	05-448-1341	CMP FPL Madison Electric Works	6,057	5,874	5,138	4,830	4,125	4,649	5,210	4,710	4,480	4,520	5,320	5,720	60,633	5,053
9	VELCO/VT Transco	113	00-697-1352	Public Service of New Hampshire	23,767	23,026	21,837	20,724	21,487	24,585	27,991	24,129	21,048	21,565	21,111	22,774	274,044	22,837
7	NU	114	XX-XXS-5555	Town of Wolfeboro Municipal Elec Dept	13,357	12,020	11,409	9,469	9,763	10,913	15,661	12,231	9,848	9,747	10,405	10,962	135,785	11,315

					LOAD VALUE (kW)													
					Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Total Annual Network Load	Average Monthly Network Load
Total Local Network Load (kW):					20,763,482	19,626,032	18,399,242	16,375,809	19,590,957	23,056,554	27,380,018	23,270,416	20,021,895	17,182,931	17,482,607	18,990,122	242,140,065	20,178,343
Local Network ID	Local Network Name																	
1	BE				4,207,369	3,992,675	3,743,125	3,368,598	4,036,469	4,824,477	5,829,009	4,986,660	4,349,628	3,563,134	3,520,025	3,783,987	50,205,156	4,183,764
2	BHE				275,035	265,721	242,294	224,301	226,634	240,440	295,125	266,820	245,236	230,237	238,919	256,873	3,007,635	250,636
4	CMP				1,431,866	1,361,537	1,297,310	1,300,660	1,238,375	1,360,303	1,633,260	1,410,910	1,312,310	1,327,310	1,303,540	1,411,510	16,388,891	1,365,741
6	NEP				5,925,622	5,594,450	5,251,126	4,608,774	5,486,919	6,624,211	7,933,061	6,747,231	5,739,226	4,813,389	4,996,836	5,440,407	69,161,252	5,763,438
7	NU				7,277,837	6,827,031	6,343,880	5,518,947	7,042,855	8,213,832	9,600,202	8,031,729	6,768,028	5,814,378	5,956,937	6,512,611	83,908,267	6,992,357
8	UI				686,663	672,274	640,969	553,526	714,247	869,980	1,048,281	890,372	771,519	603,440	601,944	640,266	8,693,481	724,457
9	VELCO/VT Transco				877,117	835,249	806,423	732,667	771,165	837,636	946,661	852,530	760,979	764,040	796,730	870,985	9,852,182	821,017
15	FGE				81,973	77,095	74,115	68,336	74,293	85,675	94,419	84,164	74,969	67,003	67,676	73,483	923,201	76,933
Total Network Load (kW)					20,763,482	19,626,032	18,399,242	16,375,809	19,590,957	23,056,554	27,380,018	23,270,416	20,021,895	17,182,931	17,482,607	18,990,122	242,140,065	20,178,343
Local Network ID	Local Network Name	Network Load ID	Duns Number	Network Load Name	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Total Annual Network Load	Average Monthly Network Load
9	VELCO/VT Transco	115	00-881-9492	New Hampshire Electric Co-op	2,762	2,551	2,375	1,770	1,719	1,900	2,322	1,855	2,064	2,172	2,137	2,902	26,529	2,211
9	VELCO/VT Transco	116	08-910-3543	Vermont Marble	24,398	29,154	28,312	29,056	23,372	22,529	25,023	24,062	0	0	0	0	205,906	17,159
9	VELCO/VT Transco	117	14-660-0585	Vermont Electric Cooperative	68,468	63,628	64,431	52,010	56,441	55,571	59,782	54,749	64,019	57,947	65,471	72,799	735,316	61,276
9	VELCO/VT Transco	118	02-065-4430	Burlington Electric Power	52,284	50,506	48,831	45,868	53,988	60,922	65,244	61,025	52,277	44,929	45,845	46,152	627,871	52,323
9	VELCO/VT Transco	119	11-923-4722	Vermont Public Power Supply Authority	82,634	76,990	75,768	64,747	58,496	63,191	74,238	66,100	60,722	66,398	68,551	80,768	838,603	69,884
9	VELCO/VT Transco	120	96-258-1922	Central Vermont Public Service	382,789	351,735	342,375	305,964	317,709	344,871	398,151	357,078	330,108	339,897	349,689	394,952	4,215,318	351,277
9	VELCO/VT Transco	121	03-647-6141	Green Mountain Power	228,858	224,071	211,887	203,503	229,515	254,699	282,186	252,945	220,016	223,001	229,704	232,300	2,792,685	232,724
7	NU	122	00-695-6551	Western Mass Electric Company	635,850	595,226	567,230	493,573	637,249	703,198	772,489	691,193	584,309	530,152	517,736	572,828	7,301,033	608,419
7	NU	123	00-691-7090	Connecticut Light and Power Co.	4,052,201	3,809,836	3,499,493	3,026,276	4,022,508	4,745,180	5,502,899	4,566,953	3,812,170	3,153,633	3,279,023	3,583,036	47,053,208	3,921,101
7	NU	124	00-697-1352	Public Service of New Hampshire	1,359,563	1,273,830	1,193,695	1,057,287	1,228,121	1,411,350	1,714,989	1,433,382	1,210,652	1,159,614	1,151,325	1,254,983	15,448,791	1,287,399
6	NEP	126	16-035-2865	Merrill Lynch Commodities, Inc.	2,515	0	0	0	0	0	0	5,525	0	0	0	0	8,040	670
6	NEP	128	17-160-5301	Dominion Manchester Street	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	NEP	129	16-872-3166	Dominion Brayton Point	0	0	0	0	0	0	0	0	0	0	18,952	0	18,952	1,579
6	NEP	130	17-160-5194	Dominion Salem Harbor	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	NEP	132	25-990-9513	Brascan Energy Marketing	357	0	0	0	41	51	0	0	0	0	0	0	449	37
1	BE	133	00-176-6328	Massport	26,955	26,240	25,678	24,425	27,473	29,574	32,303	28,244	29,573	27,750	24,337	25,628	328,180	27,348
1	BE	136	00-695-1552	NSTAR Electric Co. (NEMASS & Boston)	2,639,754	2,521,261	2,337,027	2,223,070	2,607,051	3,072,529	3,566,752	3,071,068	2,776,858	2,251,770	2,173,532	2,333,622	31,574,294	2,631,191
1	BE	137	00-695-1552	NSTAR Electric Co. (SEMASS)	868,748	814,518	777,592	624,364	764,940	964,972	1,348,064	1,127,671	879,435	742,079	757,578	817,910	10,487,871	873,989
1	BE	138	00-176-6260	MBTA - NSTAR (NEMASS & Boston)	64,141	60,252	56,847	44,134	49,106	51,286	49,222	44,019	45,485	40,331	51,989	54,669	611,481	50,957
1	BE	139	00-176-6260	MBTA - NSTAR (SEMASS)	1,830	1,980	1,852	1,777	1,340	1,516	1,584	1,732	1,326	1,767	1,708	1,603	20,015	1,668
6	NEP	140	00-695-2626	Massachusetts Electric (SEMASS)	910,764	863,187	807,966	713,428	882,134	1,064,970	1,306,362	1,114,062	914,333	746,702	781,983	854,304	10,960,195	913,350
6	NEP	141	00-695-2626	Massachusetts Electric (WCMASS)	1,629,603	1,539,931	1,457,424	1,279,274	1,532,140	1,784,009	2,010,185	1,716,595	1,520,770	1,348,405	1,362,074	1,491,570	18,671,980	1,555,998
6	NEP	142	00-695-2626	Massachusetts Electric (NEMASS & Boston)	945,285	878,132	817,268	713,442	758,402	1,039,151	1,247,944	1,011,954	874,818	732,695	763,206	818,834	10,601,131	883,428
6	NEP	143	03-647-6141	Green Mountain Power (New Hampshire)	34,298	28,736	28,037	26,621	31,553	31,239	32,256	29,146	24,475	27,416	26,061	32,387	352,225	29,352
6	NEP	144	03-647-6141	Green Mountain Power (WCMASS)	21,810	19,619	18,875	13,514	9,875	10,536	12,701	11,094	9,579	5,655	16,134	22,020	171,412	14,284
6	NEP	145	00-176-6260	NP MBTA - NEP (SEMASS)	110	40	78	80	2	2	2	2	2	45	19	29	411	34
6	NEP	146	00-176-6260	NP MBTA - NEP (WCMASS)	118	113	88	175	58	66	73	62	62	76	69	84	1,044	87
6	NEP	147	00-176-6260	NP MBTA - NEP (NEMASS & Boston)	6,653	6,263	5,300	4,245	5,071	3,980	3,721	3,719	4,753	4,163	4,693	5,882	58,443	4,870

					LOAD VALUE (kW)													
					Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Total Annual Network Load	Average Monthly Network Load
Total Local Network Load (kW):					20,763,482	19,626,032	18,399,242	16,375,809	19,590,957	23,056,554	27,380,018	23,270,416	20,021,895	17,182,931	17,482,607	18,990,122	242,140,065	20,178,343
Local Network ID	Local Network Name																	
1	BE				4,207,369	3,992,675	3,743,125	3,368,598	4,036,469	4,824,477	5,829,009	4,986,660	4,349,628	3,563,134	3,520,025	3,783,987	50,205,156	4,183,764
2	BHE				275,035	265,721	242,294	224,301	226,634	240,440	295,125	266,820	245,236	230,237	238,919	256,873	3,007,635	250,636
4	CMP				1,431,866	1,361,537	1,297,310	1,300,660	1,238,375	1,360,303	1,633,260	1,410,910	1,312,310	1,327,310	1,303,540	1,411,510	16,388,891	1,365,741
6	NEP				5,925,622	5,594,450	5,251,126	4,608,774	5,486,919	6,624,211	7,933,061	6,747,231	5,739,226	4,813,389	4,996,836	5,440,407	69,161,252	5,763,438
7	NU				7,277,837	6,827,031	6,343,880	5,518,947	7,042,855	8,213,832	9,600,202	8,031,729	6,768,028	5,814,378	5,956,937	6,512,611	83,908,267	6,992,357
8	UI				686,663	672,274	640,969	553,526	714,247	869,980	1,048,281	890,372	771,519	603,440	601,944	640,266	8,693,481	724,457
9	VELCO/VT Transco				877,117	835,249	806,423	732,667	771,165	837,636	946,661	852,530	760,979	764,040	796,730	870,985	9,852,182	821,017
15	FGE				81,973	77,095	74,115	68,336	74,293	85,675	94,419	84,164	74,969	67,003	67,676	73,483	923,201	76,933
Total Network Load (kW)					20,763,482	19,626,032	18,399,242	16,375,809	19,590,957	23,056,554	27,380,018	23,270,416	20,021,895	17,182,931	17,482,607	18,990,122	242,140,065	20,178,343
Local Network ID	Local Network Name	Network Load ID	Duns Number	Network Load Name	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Total Annual Network Load	Average Monthly Network Load
6	NEP	150	01-426-7137	Transcanada Power Marketing (NH)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	NEP	151	01-426-7137	Transcanada Power Marketing (WCMass)	153	101	90	73	63	216	202	109	7	104	87	149	1,354	113
1	BE	152	00-799-8644	NP - Nantucket (R W)	25,142	21,529	21,393	15,287	19,466	22,708	37,390	36,633	25,249	20,861	20,161	20,407	286,226	23,852
1	BE	153	05-448-1341	N EA Bellingham	1,968	0	1,252	0	2,225	0	0	0	0	0	1,090	1,073	7,608	634
1	BE	154	02-606-6550	MATEP, LLC	11,513	12,814	15,096	21,480	21,006	22,656	7,189	14,370	22,816	16,521	12,978	14,575	193,014	16,085
6	NEP	155	02-825-5979	Somerset Power station service	660	654	594	552	390	396	378	378	378	420	450	438	5,688	474
6	NEP	156	10-106-9263	BG Dighton Power station service										0	0		0	0
6	NEP	156	78-508-7888	BG Dighton Power station service	0	0	0	0	0	0	0	0	0				0	0
6	NEP	156	96-439-5342	BG Dighton Power station service												497	497	41
7	NU	157	80-693-1007	Milford Power	0	0	0	540	0	0	0	0	0	0	0	0	540	45
15	FGE	158	00-695-4317	Fitchburg Gas & Electric Light Company	81,973	77,095	74,115	68,336	74,293	85,675	94,419	84,164	74,969	67,003	67,676	73,483	923,201	76,933
7	NU	159	02-825-5979	Devon Off-line Sta. Serv.Load	850	1,049	722	660	341	354	390	356	329	471	566	628	6,716	560
7	NU	160	02-825-5979	Middletown Off-line Sta. Serv.Load	1,691	2,200	1,842	1,708	1,308	1,526	7,040	1,619	1,444	1,984	1,559	1,599	25,520	2,127
7	NU	161	02-825-5979	Montville Off-line Sta. Serv.Load	11	1,351	1,329	1,266	966	915	1,236	710	840	1,157	1,161	1,214	12,156	1,013
7	NU	162	02-825-5979	Norwalk Harbor Off-line Sta. Serv.Load	0	1,032	969	931	753	2,596	1,502	1,064	975	956	829	880	12,487	1,041
7	NU	163	04-042-2193	MP2 Offline Station Service Load	0	0	0	0	0	0	0	0	25,561	0	0	0	25,561	2,130
7	NU	164	04-042-2193	MP3 Offline Station Service Load	0	0	0	0	0	0	0	0	0	3,411	0	0	3,411	284
9	VELCO/VT Transco	165	02-813-4570	Town of Stowe Electric Dept.	11,157	13,588	10,607	9,025	8,438	9,368	11,724	10,587	10,725	8,131	14,222	18,338	135,910	11,326
7	NU	166	82-524-2444	Waterbury Generation Sta. Srv. Load	0	0	186	114	0	0	0	207	0	0	0	0	507	42
8	UI	168	05-448-1341	Bridgeport Energy-Station Service	3,900	0	0	0	0	0	0						3,900	325
8	UI	168	24-309-3411	Bridgeport Energy-Station Service								0	0	450	0	0	450	38
6	NEP	169	01-821-3640	ANP Power Milford	562	734	475	86	216	0	0	0	0	1,080	346	0	3,499	292
6	NEP	170	13-038-5763	L'Energia Montgomery							346	0	0	0	0	432	778	65
6	NEP	170	82-893-7941	L'Energia Montgomery	634	461	461	317	346	0							2,219	185
7	NU	171	00-347-1322	Kleen Energy Station Service Load	2,253	2,146	2,276	2,186	1,700	4,903	0	0	0	0	0	0	15,464	1,289
7	NU	172	01-580-7673	GenConn Devon Units 15-18 offline s/s	835	0	735	589	0	239	0	513	504	565	557	523	5,060	422
7	NU	173	01-580-7673	GenConn Middletown 12-15 offline s/s	0	0	0	490	301	233	0	425	158	419	0	470	2,496	208
1	BE	174	00-195-0773	SEMASS Station Service	0	0	0	0	0	0	0	0	0	0	0	0	0	0

					LOAD VALUE (kW)													
					Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Total Annual Network Load	Average Monthly Network Load
Total Local Network Load (kW):					20,763,482	19,626,032	18,399,242	16,375,809	19,590,957	23,056,554	27,380,018	23,270,416	20,021,895	17,182,931	17,482,607	18,990,122	242,140,065	20,178,343
Local Network ID	Local Network Name																	
1	BE				4,207,369	3,992,675	3,743,125	3,368,598	4,036,469	4,824,477	5,829,009	4,986,660	4,349,628	3,563,134	3,520,025	3,783,987	50,205,156	4,183,764
2	BHE				275,035	265,721	242,294	224,301	226,634	240,440	295,125	266,820	245,236	230,237	238,919	256,873	3,007,635	250,636
4	CMP				1,431,866	1,361,537	1,297,310	1,300,660	1,238,375	1,360,303	1,633,260	1,410,910	1,312,310	1,327,310	1,303,540	1,411,510	16,388,891	1,365,741
6	NEP				5,925,622	5,594,450	5,251,126	4,608,774	5,486,919	6,624,211	7,933,061	6,747,231	5,739,226	4,813,389	4,996,836	5,440,407	69,161,252	5,763,438
7	NU				7,277,837	6,827,031	6,343,880	5,518,947	7,042,855	8,213,832	9,600,202	8,031,729	6,768,028	5,814,378	5,956,937	6,512,611	83,908,267	6,992,357
8	UI				686,663	672,274	640,969	553,526	714,247	869,980	1,048,281	890,372	771,519	603,440	601,944	640,266	8,693,481	724,457
9	VELCO/VT Transco				877,117	835,249	806,423	732,667	771,165	837,636	946,661	852,530	760,979	764,040	796,730	870,985	9,852,182	821,017
15	FGE				81,973	77,095	74,115	68,336	74,293	85,675	94,419	84,164	74,969	67,003	67,676	73,483	923,201	76,933
					LOAD VALUE (kW)													
Total Network Load (kW)					20,763,482	19,626,032	18,399,242	16,375,809	19,590,957	23,056,554	27,380,018	23,270,416	20,021,895	17,182,931	17,482,607	18,990,122	242,140,065	20,178,343
Local Network ID	Local Network Name	Network Load ID	Duns Number	Network Load Name	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Total Annual Network Load	Average Monthly Network Load
7	NU	175	82-857-9206	Granite Reliable Power offline s/s									0	269	0	0	269	22
7	NU	176	78-413-2388	Northfield Mt Off Line Station Srv											262	225	487	41
7	NU	177	78-413-2388	Cabot Off Line Station Srv												0	0	0
7	NU	178	78-413-2388	Mt. Tom Station Service Load												1,294	1,294	108

Attachment 2

**PTOs' Annual Transmission Revenue Requirement Calculations
Pursuant to Attachment F
Based on 2011 Actual Data, 2012 Forecasted Data and Annual True-up**

ISO Tariff Billing
PTO Annual Transmission Revenue Requirements
per OATT Attachment F

Shading denotes an input

Submitted on: 14 May 2012

Revenue Requirements for (year): Calendar Year 2012

Customer: Bangor Hydro Electric Company

Customer's NABs Number: 002

Name of Participant responsible for customer's billing: Bangor Hydro Electric Company

DUNs number of Participant responsible for customer's billing: 006949002

	Pre-97 Revenue Requirements	Post-96 Revenue Requirements
Total of Attachment F - Sections A through I	\$857,579 (a)	\$37,892,127 (f)
Total of Attachment F - Section J - Support Revenue	<u>\$0 (b)</u>	<u>\$0 (g)</u>
Total of Attachment F - Section K - Support Expense	<u>\$147,594 (c)</u>	<u>\$0 (h)</u>
Total of Attachment F - Section (L through O)	(\$14,864) (d)	(\$634,942) (i)
Sub Total - Sum (A through I) - J + K + (L through O)	<u>\$990,309 (e)=(a)-(b)+(c)+(d)</u>	<u>\$37,257,185 (j)</u>
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	<u>NA</u>	<u>\$12,563,562 (k)</u>
Annual True-up (per Attachment C to Attachment F Implementation Rule)	(\$197,432) (l)	(\$2,840,832) (m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)	<u>\$792,877 (n)=(e)+(l)</u>	<u>\$46,979,915 (o)=(j)+(k)+(m)</u>
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals, Forecasted Revenue Requirements, and True-ups (including interest).		<u>\$47,772,792 (p) = (n) + (o)</u>

Bangor Hydro Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2011
PRE-1997

Shading denotes an input

		Attachment F		
		Reference		
Line No.		Section:	Total	Reference
I. INVESTMENT BASE				
1	Transmission Plant	(A)(1)(a)	5,382,079	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	80,006	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		5,462,085	
5	Accumulated Depreciation	(A)(1)(d)	(568,159)	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	(766,749)	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	0	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	(63,564)	Worksheet 3, line 15 column 5
9	Net Investment (Line 4+5+6+7+8)		4,063,613	
10	Prepayments	(A)(1)(h)	11,624	Worksheet 3, line 16 column 5
11	Materials & Supplies	(A)(1)(i)	99	Worksheet 3, line 17 column 5
12	Cash Working Capital	(A)(1)(j)	24,852	Worksheet 3, line 24 column 5
13	Total Investment Base (Line 9+10+11+12)		4,100,188	
II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	650,571	Worksheet 2
15	Depreciation Expense	(B)	106,862	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	0	Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)	(421)	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	47,646	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	1,700	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	(G)	30,768	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	20,453	Worksheet 4, line 22 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	147,594	Worksheet 7
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	0	
27	Revenue for ST Trans. Service Under ISO Tariff	(N)	(19,087)	from G/L
28	Transmission Rents Received from Electric Property	(O)	4,222	Exhibit: Transmission Rents
29	Total Revenue Requirements (Line 14 thru 28)		990,309	

Bangor Hydro Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2011
POST-1996

Shading denotes an input

		Attachment F				
Line No.		Reference	Post-96 (less NRI)	NRI	Total	Reference
I. INVESTMENT BASE						
1	Transmission Plant	(A)(1)(a)	87,764,978	142,132,418	229,897,396	from GL, Worksheet 3 line 1
2	General Plant	(A)(1)(b)	3,417,589	n/a	3,417,589	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	0	n/a	0	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		91,182,567	142,132,418	233,314,985	
5	Accumulated Depreciation	(A)(1)(d)	(15,185,288)	(9,084,464)	(24,269,752)	from GL / Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	(20,256,207)	(12,496,607)	(32,752,814)	from GL / Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	0	n/a	0	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	(2,715,245)	n/a	(2,715,245)	Worksheet 3, line 15 column 5
9	Net Investment (Line 4+5+6+7+8)		53,025,827	120,551,347	173,577,174	
10	Prepayments	(A)(1)(h)	496,545	n/a	496,545	Worksheet 3, line 16 column 5
11	Materials & Supplies	(A)(1)(i)	4,237	n/a	4,237	Worksheet 3, line 17 column 5
12	Cash Working Capital	(A)(1)(j)	273,494	n/a	273,494	Worksheet 3, line 24 column 5
13	Total Investment Base (Line 9+10+11+12)		53,800,103	120,551,347	174,351,450	
II. REVENUE REQUIREMENTS						
			Post-96 (less NRI)	NRI	Total	
14	Investment Return and Income Taxes	(A)	27,664,676	1,384,809	29,049,485	Worksheet 2
15	Depreciation Expense	(B)			4,564,758	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)			0	Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)			(17,964)	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)			2,035,275	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)			72,621	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	(G)			1,314,320	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)			873,632	Worksheet 4, line 22 column 5
22	Transmission Related Integrated Facilities Charge	(I)			0	Worksheet 7
23	Transmission Support Revenue	(J)			0	Worksheet 7
24	Transmission Support Expense	(K)			0	Worksheet 7
25	Transmission Related Expense from Generators	(L)			0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)			0	
27	Revenue for ST Trans. Service Under ISO Tariff	(N)			(815,292)	from G/L
28	Transmission Rents Received from Electric Property	(O)			180,350	Exhibit: Transmission Rents
29	Total Revenue Requirements (Line 14 thru 28)				37,257,185	

Bangor Hydro Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2011
PRE-1997

Shading denotes an input

	CAPITALIZATION 12/31/2011	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 151,818,180	31.57%	7.39%	2.33%	
PREFERRED STOCK	382,000	0.08%	7.24%	0.01%	0.01%
COMMON EQUITY	328,723,068	68.35%	11.64%	7.96%	7.96%
TOTAL INVESTMENT RETURN	\$ 480,923,248	100.00%		10.30%	7.97%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.1030

$$\begin{aligned}
 \text{(b) Federal Income Tax} &= \left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right)}{1} \right) \times \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}} \\
 &= \left(\frac{0.0797 + \left(\frac{(421) + 4,762}{4,100,188} \right)}{1} \right) \times \frac{0.35}{0.35} \\
 &= \underline{\underline{0.0434855}}
 \end{aligned}$$

$$\begin{aligned}
 \text{(c) State Income Tax} &= \left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right)}{1} \right) + \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}} \times \text{State Income Tax Rate} \\
 &= \left(\frac{0.0797 + \left(\frac{(421) + 4,762}{4,100,188} \right)}{1} \right) + \frac{0.0434855}{0.0893} \times 0.0893 \\
 &= \underline{\underline{0.0121830}}
 \end{aligned}$$

(a)+(b)+(c) Cost of Capital Rate = 0.1586685

	(PTF)	
INVESTMENT BASE	\$ 4,100,188	From Worksheet 1
x Cost of Capital Rate	0.1586685	
= Investment Return and Income Taxes	<u>650,571</u>	To Worksheet 1

Bangor Hydro Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2011
POST-1996

Shading denotes an input

	CAPITALIZATION 12/31/2011	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 151,818,180	31.57%	7.39%	2.33%	
PREFERRED STOCK	382,000	0.08%	7.24%	0.01%	0.01%
COMMON EQUITY	328,723,068	68.35%	11.64%	7.96%	7.96%
TOTAL INVESTMENT RETURN	\$ <u>480,923,248</u>	<u>100.00%</u>		<u>10.30%</u>	<u>7.97%</u>

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.1030

$$\begin{aligned}
 \text{(b) Federal Income Tax} &= \left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right)}{1} \right) \times \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}} \\
 &= \left(\frac{0.0797 + \left(\frac{(17,964) + 203,432}{174,351,450} \right)}{1} \right) \times \frac{0.35}{0.35} \\
 &= \underline{0.0434882}
 \end{aligned}$$

$$\begin{aligned}
 \text{(c) State Income Tax} &= \left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right)}{1} \right) + \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}} \times \text{State Income Tax Rate} \\
 &= \left(\frac{0.0797 + \left(\frac{(17,964) + 203,432}{174,351,450} \right)}{1} \right) + \frac{0.0434882}{0.0893} \times 0.0893 \\
 &= \underline{0.0121837}
 \end{aligned}$$

(a)+(b)+(c) Cost of Capital Rate = 0.1586719

	(PTF)	
INVESTMENT BASE	\$ 174,351,450	From Worksheet 1
x Cost of Capital Rate	0.1586719	
= Investment Return and Income Taxes	<u>27,664,676</u>	To Worksheet 1

Bangor Hydro Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2011
POST-2003 (NRI)

Shading denotes an input

	CAPITALIZATION 12/31/2011	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 151,818,180	31.57%	0.00%	0.00%	
PREFERRED STOCK	382,000	0.08%	0.00%	0.00%	0.00%
COMMON EQUITY	328,723,068	68.35%	1.0%	0.68%	0.68%
TOTAL INVESTMENT RETURN	\$ 480,923,248	100.00%		0.68%	0.68%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0068

(b) Federal Income Tax = $\left(\frac{\text{R.O.E.}}{1} \times \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}} \right)$

= $\left(\frac{0.0068}{1} \times \frac{0.35}{0.35} \right)$

= 0.0036615

(c) State Income Tax = $\left(\frac{\text{R.O.E.}}{1} + \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}} \right) \times \text{State Income Tax Rate}$

= $\left(\frac{0.0068}{1} + \frac{0.0036615}{0.0893} \right) \times 0.0893$

= 0.0010258

(a)+(b)+(c) Cost of Capital Rate = 0.0114873

	(PTF)	
INVESTMENT BASE (NRI)	\$ 120,551,347	From Worksheet 1
x Cost of Capital Rate	0.0114873	
= Investment Return and Income Taxes	<u>1,384,809</u>	To Worksheet 1

Bangor Hydro Electric Company (BHE)
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For Costs In 2011
PRE-1997

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
<u>Transmission Plant</u>						
1	Transmission Plant				5,382,079	Line 1, Worksheet 5
2	General Plant	47,275,067	10.7670% (a)	5,090,106	80,006	Page 207.96g
3	Total (line 1+2)			5,090,106	5,462,085	
4	<u>Transmission Plant Held for Future Use</u>	0		0	0	Page 214
<u>Transmission Accumulated Depreciation</u>						
5	Transmission Accum. Depreciation	(34,139,522)		(34,139,522)	(536,605)	Page 219.25b
6	General Plant Accum. Depreciation	(18,644,805)	10.7670% (a)	(2,007,486)	(31,554)	Page 219.28b
7	Total (line 5+6)			(36,147,008)	(568,159)	
<u>Transmission Accumulated Deferred Taxes</u>						
8	Accumulated Deferred Taxes (281-283)			(54,360,347) (d)	(854,436)	Page 450.1 Footnote
9	Accumulated Deferred Taxes (190)			5,578,791 (e)	87,687	Page 234 Footnote
10	Total (line 8+9)			(48,781,556)	(766,749)	
11	<u>Transmission loss on Reacquired Debt</u>	0	50.7572% (c)	0	0	Page 111.81c
<u>Other Regulatory Assets</u>						
12	FAS 106	(37,559,623)	10.7670% (a)	(4,044,045)	(63,564)	Page 232.23f - Page 278.1f + part of Page 122a (Column C)
13	FAS 109	0	(f)	0	0	FAS 106 portion of AOCI
14	Other Regulatory Liabilities (254.DK)	0	50.7572% (c)	0	0	Excluded in Lines 8 & 9
15	Total (line 12+13+14)	(37,559,623)		(4,044,045)	(63,564)	n/a
16	<u>Transmission Prepayments</u>	6,868,646	10.7670% (a)	739,547	11,624	Page 111.57c
17	<u>Transmission Materials and Supplies</u>	6,310		6,310	99	Page 227.8c
18	<u>Cash Working Capital</u>			99		
19	Operation & Maintenance Expense				30,768	Worksheet 1, Line 20
20	Administrative & General Expense				20,453	Worksheet 1, Line 21
21	Transmission Support Expense				147,594	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)				198,815	
23					0.125	x 45 / 360
24	Total (line 22 * line 23)				24,852	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

(d) Directly assigned to transmission as per the FERC Form 1, page 450.1 footnote on functionalization

(e) Directly assigned to transmission as per the FERC Form 1, page 234 footnote on functionalization

(f) Zero because FAS 109 balances were excluded on Lines 8 & 9

Bangor Hydro Electric Company (BHE)
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POST-1996

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
<u>Transmission Plant</u>						
1			0		229,897,396	Line 1, Worksheet 5
2	47,275,067	10.7670% (a)	5,090,106	67.1418%	3,417,589	Page 207.96g
3			5,090,106		233,314,985	
4	0		0	67.1418%	0	Page 214
<u>Transmission Accumulated Depreciation</u>						
5	(34,139,522)		(34,139,522)	67.1418%	(22,921,890)	Page 219.25b
6	(18,644,805)	10.7670% (a)	(2,007,486)	67.1418%	(1,347,862)	Page 219.28b
7			(36,147,008)		(24,269,752)	
<u>Transmission Accumulated Deferred Taxes</u>						
8			(54,360,347) (d)	67.1418%	(36,498,515)	Page 450.1
9			5,578,791 (e)	67.1418%	3,745,701	Page 234 Footnote
10			(48,781,556)		(32,752,814)	
11	0	50.7572% (c)	0	67.1418%	0	Page 111.81c
<u>Other Regulatory Assets</u>						
12	(37,559,623)	10.7670% (a)	(4,044,045)	67.1418%	(2,715,245)	Page 232.23f - Page 278.1f + part of
13	0	50.7572% (c)	0	67.1418%	0	Page 122a (Column C)
14	0	50.7572% (c)	0	67.1418%	0	Excluded in Lines 8 & 9
15	(37,559,623)		(4,044,045)		(2,715,245)	n/a
16	6,868,646	10.7670% (a)	739,547	67.1418%	496,545	Page 111.57c
17	6,310		6,310	67.1418%	4,237	Page 227.8c
<u>Cash Working Capital</u>						
19					1,314,320	Worksheet 1, Line 20
20					873,632	Worksheet 1, Line 21
21					0	Worksheet 1, Line 24
22					2,187,952	
23					0.125	x 45 / 360
24					273,494	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

(d) Directly assigned to transmission as per the FERC Form 1, page 450.1 footnote on functionalization

(e) Directly assigned to transmission as per the FERC Form 1, page 234 footnote on functionalization

(f) Zero because FAS 109 balances were excluded on Lines 8 & 9

Bangor Hydro Electric Company (BHE)
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For Costs In 2011
PRE-1997

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
	<u>Depreciation Expense</u>					
1	6,521,122		6,521,122	1.5718%	102,499	Page 336.7b
2	2,577,881	10.7670% (a)	277,560	1.5718%	4,363	Page 336.10b
3			6,798,682		106,862	
4	0	50.7572% (c)	0	1.5718%	0	Page 117.64c
5	52,711	50.7572% (c)	26,755	1.5718%	421	Page 266.8f
	<u>Property Taxes</u>					
6	5,972,176	50.7572% (c)	3,031,309	1.5718%	47,646	Page 262-263, Note d
8			3,031,309		47,646	
	<u>Transmission Operation and Maintenance</u>					
9	(19,604,099)		(19,604,099)	1.5718%	(308,137)	Page 321.112b
10	(22,351,392)		(22,351,392)	1.5718%	(351,319)	Page 321.96b
11	789,765		789,765	1.5718%	12,414	Page 321.84b-88b
12					0	Page 321.93b & .98b
13	1,957,528		1,957,528	1.5718%	30,768	
	<u>Transmission Administrative and General</u>					
14	10,964,330					Page 323.197b
15	224,712					Page 323.185b
16	1,160,909					Page 350 (351.46[h+k])
17	0					Page 323.191b
18	9,578,709	10.7670% (a)	1,031,340	1.5718%	16,211	
19	224,712	50.7572% (c)	114,058	1.5718%	1,793	
20	306,906	50.7572% (c)	155,777	1.5718%	2,449	Exhibit: Reg Comission Expenses
21	0	50.7572% (c)	0	1.5718%	0	
22	10,110,327		1,301,175		20,453	
23	1,004,547	10.7670% (a)	108,160	1.5718%	1,700	Footnote (d)
Notes:	(a) Worksheet 5 of 7, line 11					
	(b) Worksheet 5 of 7, line 3					
	(c) Worksheet 5 of 7, line 16					
	(d) Payroll taxes FERC Form 1					
	Federal Unemployment	10.888	page 263.9i			
	FICA	971,937	page 263.6i			
	Medicare	0				
	State Unemployment	21,722	page 263.13i			
	Total	1,004,547	To Line 23			
** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments.						
	<u>Appropriate Property Taxes</u>					
	BHE 2011	5,144,189	page 263.17i			
	BHE 2010	827,987	page 263.18i			
	Total	5,972,176	To Line 6			

Bangor Hydro Electric Company (BHE)
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For Costs In 2011
POST-1996

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
<u>Depreciation Expense</u>						
1	6,521,122		6,521,122	67.1418%	4,378,399	Page 336.7b
2	2,577,881	10.7670% (a)	277,560	67.1418%	186,359	Page 336.10b
3			6,798,682		4,564,758	
4	0	50.7572% (c)	0	67.1418%	0	Page 117.64c
5	52,711	50.7572% (c)	26,755	67.1418%	17,964	Page 266.8f
<u>Property Taxes</u>						
6	5,972,176	50.7572% (c)	3,031,309	67.1418%	2,035,275	Page 262-263 FN.1-2
8			3,031,309		2,035,275	
<u>Transmission Operation and Maintenance</u>						
9	(19,604,099)		(19,604,099)	67.1418%	(13,162,545)	Page 321.112b
10	(22,351,392)		(22,351,392)	67.1418%	(15,007,127)	Page 321.96b
11	789,765		789,765	67.1418%	530,262	Page 321.84b-88b
12					0	Page 321.93b & .98b
13	1,957,528		1,957,528	67.1418%	1,314,320	
<u>Transmission Administrative and General</u>						
14	10,964,330					Page 323.197b
15	224,712					Page 323.185b
16	1,160,909					Page 350 (351.46[h+k])
17	0					Page 323.191b
18	9,578,709	10.7670% (a)	1,031,340	67.1418%	692,460	
19	224,712	50.7572% (c)	114,058	67.1418%	76,581	
20	306,906	50.7572% (c)	155,777	67.1418%	104,591	Exhibit: Reg
21	0	50.7572% (c)	0	67.1418%	0	Comission Expenses
22	10,110,327		1,301,175		873,632	
23	1,004,547	10.7670% (a)	108,160	67.1418%	72,621	Footnote (d)
Notes: (a) Worksheet 5 of 7, line 11						
(b) Worksheet 5 of 7, line 3						
(c) Worksheet 5 of 7, line 16						
(d) Payroll taxes FERC Form 1, page 263.i ,263.1i						
	10,888					
	FICA	971,937				
	Medicare	0				
	State Unemployment	21,722				
	Total	1,004,547	To Line 23			
** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments.						
Appropriate Property Taxes						
	BHE 2011	5,144,189				
	BHE 2010	827,987				
	Total	5,972,176	To Line 6			

Bangor Hydro Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2011
PRE-1997

Shading denotes an input

Line No.		Total	FERC Form 1 Reference
<u>PTF Transmission Plant Allocation Factor</u>			
1	PTF Transmission Investment	5,382,079	Exhibit PTF Plant Page 207.58g
2	Total Transmission Investment	342,405,916	
3	Percent Allocation (Line 1/Line 2)	1.5718%	
<u>Transmission Wages and Salaries Allocation Factor</u>			
4	Direct Transmission Wages and Salaries	1,255,746	Page 354.21b Worksheet 6
5	Affiliated Company Transmission Wages and Salaries	0	
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	1,255,746	
7	Total Wages and Salaries	15,063,147	Page 354.28b Page 354.27b Worksheet 6
8	Administrative and General Wages and Salaries	3,400,264	
9	Affiliated Company Wages and Salaries less A&G	0	
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	11,662,883	
11	Percent Allocation (Line 6/Line 10)	10.7670%	
<u>Plant Allocation Factor</u>			
12	Total Transmission Investment	342,405,916	Page 207.58g Worksheet 3, Line 2
13	plus Transmission-Related General Plant (Line 2 of Wkst. 3)	5,090,106	
14	= Revised Numerator (Line 12 + Line 13)	347,496,022	
15	Total Plant in Service	684,624,735	Page 207.104g
16	Percent Allocation (Line 14 / Line 15)	50.7572%	

Bangor Hydro Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2011
POST-1996

Shading denotes an input

Line No.		Total	FERC Form 1 Reference
<u>PTF Transmission Plant Allocation Factor</u>			
1	PTF Transmission Investment	229,897,396	Exhibit PTF Plant
2	Total Transmission Investment	342,405,916	Page 207.58g
3	Percent Allocation (Line 1/Line 2)	67.1418%	
<u>Transmission Wages and Salaries Allocation Factor</u>			
4	Direct Transmission Wages and Salaries	1,255,746	Page 354.21b
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	1,255,746	
7	Total Wages and Salaries	15,063,147	Page 354.28b
8	Administrative and General Wages and Salaries	3,400,264	Page 354.27b
9	Affiliated Company Wages and Salaries less A&G	0	Worksheet 6
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	11,662,883	
11	Percent Allocation (Line 6/Line 10)	10.7670%	
<u>Plant Allocation Factor</u>			
12	Total Transmission Investment	342,405,916	Page 207.58g
13	plus Transmission-Related General Plant (Line 2 of Wkst. 3)	5,090,106	Worksheet 3, Line 2
14	= Revised Numerator (Line 12 + Line 13)	347,496,022	
15	Total Plant in Service	684,624,735	Page 207.104g
16	Percent Allocation (Line 14 / Line 15)	50.7572%	

Bangor Hydro Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2011
Affiliated Company Wages and Salaries

Shading denotes an input

Line		Total
"Affiliated" Transmission Wages and Salaries #560 - 573		
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11 = 1 thru 10	Total Transmission	0
12 = Total "Affiliated" Wages and Salaries		0
Less "Affiliated" Administrative and General Salaries #920 - 935		
13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
21 = 13 thru 20		0
22 = 12 less 21	Total "Affiliated" less A&G	0

Bangor Hydro Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2011

Shading denotes an input

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	FERC Form 1	Total	
			Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	332.(h)		6,905
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			
	115 kV Maine Yankee transmission			
	115 kV Orrington Substation			
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			41,693
	Comerford 115 kV Substation			
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation			
	HQ Phase II - AC in MA	332.(h)		98,996
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 394 line			
NU	115 kV Read - Washington V148 line			
	345 kV 363, 369 and 394 Seabrook lines			
	Fairmont 115 kV Substation			
	345 kV Millstone-Manchester 310 line			
	UI Substations			
Black Pond				
Total =			0	147,594

Amount by which Support Expense exceeds Support Revenues
 (To Worksheet 3, Line 21, Column 5)

147,594

Bangor Hydro Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2011
TRUE-UP

Shading denotes an input

I. ANNUAL TRUE-UP		Period	Attachment F Reference Section:	PRE97	POST 1996	Reference
Line No.						
1	Prior Year (Billed) Revenue Requirement	06/10-05/11	Appendix C	\$1,181,374	\$40,006,404	Sub-Total ATRR plus FTRR (excludes ATU) "Summary", line 29 (before FTRR & ATU)
2	Prior Year (Actual) Revenue Requirement	TY 2011		\$990,309	\$37,257,185	
3	Under / (Over) Forecast (Lines 2 - 1)			(\$191,065)	(\$2,749,219)	
4	Annual True Up (ATU)	06/10-05/11		(\$191,065)	(\$2,749,219)	

Bangor Hydro Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2011
FORECAST

Shading denotes an input

Attachment F

Reference

I. <u>FORECASTED TRANSMISSION REVENUE REQUIREMENTS</u>		Period	Section:	POST-1996	Reference
Line No.					
1	Forecasted Transmission Plant Additions	2010	Appendix C	\$76,225,077	Exh :Forecast Plant
2	Carrying Charge Factor		Appendix C	16.48%	
3	Total Forecasted Revenue Requirements (Lines 1*2)			<u>\$12,563,562</u>	
II. <u>CARRYING CHARGE FACTOR</u>					
4	Investment Return and Income Taxes		(A)	\$29,049,485	Worksheet 1 Post-96, line 14
5	Depreciation Expense		(B)	\$4,564,758	Worksheet 1 Post-96, line 15
6	Amortization of Loss on Reacquired Debt		(C)	\$0	Worksheet 1 Post-96, line 16
7	Investment Tax Credit		(D)	(\$17,964)	Worksheet 1 Post-96, line 17
8	Property Tax Expense		(E)	\$2,035,275	Worksheet 1 Post-96, line 18
9	Payroll Tax Expense		(F)	\$72,621	Worksheet 1 Post-96, line 19
10	Operation & Maintenance Expense		(G)	\$1,314,320	Worksheet 1 Post-96, line 20
11	Administrative & General Expense		(H)	\$873,632	Worksheet 1 Post-96, line 21
12	Total Expenses (Lines 4 thru 11)			<u>\$37,892,127</u>	
13	PTF Transmission Plant		(A)(1)(a)	<u>\$229,897,396</u>	Worksheet 1 Post-96, line 1
14	Carrying Charge Factor (Lines 12/13)			<u>16.48%</u>	

Bangor Hydro Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2011
SUMMARY

Line No.		Attachment F Reference Section:	Pre-97 Total	Post-96 Total	Reference
I. INVESTMENT BASE					
1	Transmission Plant	(A)(1)(a)	5,382,079	229,897,396	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	80,006	3,417,589	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	0	0	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		5,462,085	233,314,985	
5	Accumulated Depreciation	(A)(1)(d)	(568,159)	(24,269,752)	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	(766,749)	(32,752,814)	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	0	0	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	(63,564)	(2,715,245)	Worksheet 3, line 15 column 5
9	Net Investment (Line 4+5+6+7+8)		4,063,613	173,577,174	
10	Prepayments	(A)(1)(h)	11,624	496,545	Worksheet 3, line 16 column 5
11	Materials & Supplies	(A)(1)(i)	99	4,237	Worksheet 3, line 17 column 5
12	Cash Working Capital	(A)(1)(j)	24,852	273,494	Worksheet 3, line 24 column 5
13	Total Investment Base (Line 9+10+11+12)		4,100,188	174,351,450	
II. REVENUE REQUIREMENTS					
14	Investment Return and Income Taxes	(A)	650,571	29,049,485	Worksheet 2
15	Depreciation Expense	(B)	106,862	4,564,758	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	0	0	Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)	(421)	(17,964)	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	47,646	2,035,275	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	1,700	72,621	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	(G)	30,768	1,314,320	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	20,453	873,632	Worksheet 4, line 22 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	0	Worksheet 7
24	Transmission Support Expense	(K)	147,594	0	Worksheet 7
25	Transmission Related Expense from Generators	(L)	0	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	0	0	
27	Revenue for ST Trans. Service Under ISO Tariff	(N)	(19,087)	(815,292)	Worksheet 1, line 27
28	Transmission Rents Received from Electric Property	(O)	4,222	180,350	Worksheet 1, line 28
29	Total Revenue Requirements (Line 14 thru 28)		990,309	37,257,185	

Interest

**Bangor Hydro Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2011
INTEREST**

Shading denotes an input

Pre 97 Under / (Over) (\$191,065)	Post-96 Under/ (Over) (\$2,749,219)

Initial Billing Period	Pre-97 Balance	Post-96 Balance	FERC Monthly Interest Rate	Pre-97 Interest	Post-96 Interest
June-11	\$ (191,065)	\$ (2,749,219)	0.27%	\$ (516)	\$ (7,423)
July-11	\$ (191,581)	\$ (2,756,642)	0.27%	\$ (517)	\$ (7,443)
August-11	\$ (191,581)	\$ (2,756,642)	0.28%	\$ (536)	\$ (7,719)
September-11	\$ (191,581)	\$ (2,756,642)	0.27%	\$ (517)	\$ (7,443)
October-11	\$ (193,152)	\$ (2,779,247)	0.28%	\$ (541)	\$ (7,782)
November-11	\$ (193,152)	\$ (2,779,247)	0.27%	\$ (522)	\$ (7,504)
December-11	\$ (193,152)	\$ (2,779,247)	0.28%	\$ (541)	\$ (7,782)
January-12	\$ (194,755)	\$ (2,802,314)	0.28%	\$ (545)	\$ (7,846)
February-12	\$ (194,755)	\$ (2,802,314)	0.26%	\$ (506)	\$ (7,286)
March-12	\$ (194,755)	\$ (2,802,314)	0.28%	\$ (545)	\$ (7,846)
April-12	\$ (196,352)	\$ (2,825,293)	0.27%	\$ (530)	\$ (7,628)
May-12	\$ (196,352)	\$ (2,825,293)	0.28%	\$ (550)	\$ (7,911)
Total Interest				\$ (6,367)	\$ (91,613)
True-Up				(\$191,065)	(\$2,749,219)
Total TU & Int				\$ (197,432)	\$ (2,840,832)

Exhibit: Regulatory Commission Expenses

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Regulatory Commission Expenses for 2011
Reconciliation of FERC Form 1 Data to Exhibit 5

Line	a Description	b Expenses Booked	c Reference
1	Expenses booked to Account 923 (directly related to reg proceedings)	\$ 37,381	Exhibit: Outside Legal Expenses (#923), line 13c
2	Regulatory commission expenses booked to Account 928	\$ 1,160,909	FF1 pg 350.46d
3	Line 2, directly attributable to Transmission		
a	Annual Federal Regulatory Assessment	\$ 163,889	FF1 pg 350.2d
b	General Transmission	\$ 59,418	FF1 pg 350.4d
c	Transmission Tariff filings	\$ 36,167	FF1 pg 350.5d
d	Stetson Lead Line Advice	\$ 8,234	FF1 pg 350.9d
e	Revision of Formula Rates	\$ 1,050	FF1 pg 350.11d
f	ROE Case FERC Docket No EL11-66	\$ 767	FF1 pg 350.12d
g			
h			
i			
4			
5	Account 928 directly related to Transmission	\$ 269,525	
6			
7			
8			
9	Total	\$ 306,906	Line 1+5+6+7
10			
11	a	b	c
12	Notes		
13	1) 2008		
14	2) 2009		
	3) 2010		

Bangor Hydro Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Transmission Rents for 2011

Line	Line	Miles	Rate (\$/mile/year)			Fee
1	Line 205	5.36	\$	3,600	\$	19,296
2	Line 246	7.22	\$	3,600	\$	25,992
3	Line 60	20.3	\$	3,600	\$	73,080
4	Line 73	2.82	\$	3,600	\$	10,152
5	Line 78	6.45	\$	3,600	\$	23,220
6	Line 77	2.57	\$	3,600	\$	9,252
7	Line 11	6.55	\$	3,600	\$	23,580
8	Total				\$	184,572

**Bangor Hydro Electric Company
2011 PTF Plant Calculation
Additions, Retirements and Transfers
Summary By FERC Account**

Line	a	b	c	d	e	f
1			2010 Total PTF Plant			
2	FERC		total	pre-97	post-96	post-03
3	350 Transmission Land	\$	13,207,845	\$ 78,755	\$ 3,371,371	\$ 9,757,720
4	353 Substations	\$	61,152,922	\$ 5,327,045	\$ 2,143,726	\$ 53,682,152
5	354 Towers and Fixtures	\$	9,312,136	\$ 26,741	\$ -	\$ 9,285,395
6	355 Poles and Fixtures	\$	66,746,722	\$ 593,719	\$ 4,022,675	\$ 62,130,328
7	356 Overhead Conductors	\$	56,226,411	\$ 401,869	\$ 3,472,915	\$ 52,351,627
8	357 Underground Conduits	\$	29	\$ -	\$ -	\$ 29
9	358 Underground Conductors	\$	17,410	\$ -	\$ -	\$ 17,410
10	359 Roads and Trails	\$	-	\$ -	\$ -	\$ -
11		\$	206,663,475	\$ 6,428,129	\$ 13,010,686	\$ 187,224,660
12						
13						
14			2011 Incremental PTF			
15	FERC		total	pre-97	post-96	post-03
16	350 Transmission Land	\$	-	\$ -	\$ -	\$ -
17	353 Substations	\$	11,878,073	\$ -	\$ -	\$ 11,878,073
18	354 Towers and Fixtures	\$	-	\$ -	\$ -	\$ -
19	355 Poles and Fixtures	\$	17,196,611	\$ (521,107)	\$ (949,350)	\$ 18,667,069
20	356 Overhead Conductors	\$	(458,697)	\$ (524,943)	\$ (12,423)	\$ 78,669
21	357 Underground Conduits	\$	-	\$ -	\$ -	\$ -
22	358 Underground Conductors	\$	12	\$ -	\$ -	\$ 12
23	359 Roads and Trails	\$	-	\$ -	\$ -	\$ -
24		\$	28,615,999	\$ (1,046,050)	\$ (961,773)	\$ 30,623,823
25						
26						
27			2011 Total PTF			
28	FERC		total	pre-97	post-96	post-03
29	350 Transmission Land	\$	13,207,845	\$ 78,755	\$ 3,371,371	\$ 9,757,720
30	353 Substations	\$	73,030,995	\$ 5,327,045	\$ 2,143,726	\$ 65,560,224
31	354 Towers and Fixtures	\$	9,312,136	\$ 26,741	\$ -	\$ 9,285,395
32	355 Poles and Fixtures	\$	83,943,333	\$ 72,612	\$ 3,073,324	\$ 80,797,397
33	356 Overhead Conductors	\$	55,767,715	\$ (123,073)	\$ 3,460,492	\$ 52,430,295
34	357 Underground Conduits	\$	29	\$ -	\$ -	\$ 29
35	358 Underground Conductors	\$	17,422	\$ -	\$ -	\$ 17,422
36	359 Roads and Trails	\$	-	\$ -	\$ -	\$ -
37		\$	235,279,475	\$ 5,382,079	\$ 12,048,913	\$ 217,848,483

Bangor Hydro Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Monthly Outside Legal Expenses (Account 923) for 2011
Reconciliation of FERC Form 1 Data to Exhibit 5

a		b		c	
Months		Total Booked Expenses		Directly Related to Regulatory and/or Compliance Activities	
1	Jan-11	\$	4,861.87		
2	Feb-11	\$	2,556.49	\$	567.00
3	Mar-11	\$	41.00		
4	Apr-11	\$	9,083.08	\$	7,760.04
5	May-11	\$	6,946.48		
6	Jun-11	\$	5,724.54	\$	4,842.54
7	Jul-11				
8	Aug-11	\$	3,822.70	\$	2,994.50
9	Sep-11				
10	Oct-11				
11	Nov-11	\$	349.55		
12	Dec-11	\$	29,619.61	\$	21,216.68
13	Total	\$	63,005.32	\$	37,380.76

Bangor Hydro Electric Company (BHE)
Annual Revenue Requirement for Transmission Facilities
Total Forecasted Transmission Plant (FTPA) for 2012

Line	Capital Additions:	<u>RSP ID</u>		PTF
1	Downeast Reliability Project	143	\$	54,190,776
2	BHE MPRP - Orrington 115kV	906	\$	2,700,000
3	BHE MPRP - Orrington MPRP 345	905	\$	15,600,000
4	SVC filter	1196	\$	3,734,301
8				
9	Total Forecasted Transmission Plant Additions = FTPA		\$	<u>76,225,077</u>

Braintree Electric Light Department

Sheet: Input Panel

Input Panel

Regional Network Service
Annual Transmission Revenue Requirements
per Attachment F of the ISO New England Inc. Open Access Transmission Tariff

Shading denotes an input

Submitted on: 05/14/2012

Revenue Requirements for (year): 2011

Customer: Braintree Electric Light Department

Customer's NABs Number: 5

Name of Participant responsible for customer's billing: William Bottiggi

DUNs number of Participant responsible for customer's billing: 17-0571897

	Pre-97 Revenue Requirements	Post-96 Revenue Requirements
Total of Attachment F - Sections A through I =	167,080 (a)	2,111,408 (f)
Total of Attachment F - Section J - Support Revenue	0 (b)	0 (g)
Total of Attachment F - Section K - Support Expense	63,600 (c)	0 (h)
Total of Attachment F - Section L through O	0 (d)	0 (i)
Sub Total - Sum (A through I) - J + K + (L through O)	230,680 (e)=(a)-(b)+(c)+(d)	2,111,408 (j)=(f)-(g)+(h)+(i)
Forecasted Incremental Transmission Revenue Requirements		0 (m)
Annual True-up	(12,761)	(31,077) (n)
Interest Charge on Annual True-up	(425) (l)	(1,036) (o)
Total = (e) + (j) + (k) + (l) + (m) + (n) + (o)	217,494 (p)	2,079,295 (q)
Annual Projected 2008 Revenue Requirement Total = Sum of Pre-97 Revenue Requirements, plus Post-96 Revenue Requirements, plus Annual True-up, and plus Interest on Annual True-up:		2,296,789 (r) = (p)+(q)

Braintree Electric Light Department
Annual Revenue Requirements of pre-1997 & post-1996 PTF
for costs in 2011 and billed 06/11-05/12

RNS Rate

		Attachment F			
		Reference	Pre 1997	Post 1996	Reference
Line No.	I. INVESTMENT BASE	Section:			
1	Transmission Plant	I (A)(1)(a)	1,703,903	21,557,662	Worksheet 3, line 1 column 5
2	General Plant	I (A)(1)(b)	14,695	199,105	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	I (A)(1)(c)	0	0	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		1,718,598	21,756,767	
5	Accumulated Depreciation	I (A)(1)(d)	685,593	9,379,119	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	I (A)(1)(e)	0	0	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	I (A)(1)(f)	0	0	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	I (A)(1)(g)	0	0	Worksheet 3, line 15 column 5
9	Net Investment (Line 4-5-6+7+8)		1,033,005	12,377,648	
10	Prepayments	I (A)(1)(h)	98	2,128	Worksheet 3, line 16 column 5
11	Materials & Supplies	I (A)(1)(i)	3,749	50,385	Worksheet 3, line 17 column 5
12	Cash Working Capital	I (A)(1)(j)	10,812	26,760	Worksheet 3, line 24 column 5
13	Total Investment Base (Line 9+11+12+13)		1,047,664	12,456,921	
II. REVENUE REQUIREMENTS					
14	Investment Return and Income Taxes	I (A)	83,813	996,554	Worksheet 2
15	Depreciation Expense	I (B)	55,729	705,074	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	I (C)	0	-	Worksheet 4, line 4 column 5
17	Investment Tax Credit	I (D)	0	-	Worksheet 4, line 5 column 5
18	Property Taxes	I (E)	15,816	206,720	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	I (F)	1,585	20,059	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	I (G)	8,233	104,163	Worksheet 4, line 13 column 5
21	Administrative & General Expense	I (H)	13,978	109,915	Worksheet 4, line 22 column 5
22	Transmission Related Integrated Facilities Charge	I (I)	0	0	
23	Transmission Support Revenue	I (J)	0	0	Worksheet 7
24	Transmission Support Expense	I (K)	64,287	0	Worksheet 7
25	Transmission Related Expense from Generators	I (L)	0	0	
26	Transmission Related Taxes and Fees Charge	I (M)	0	0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	I (N)	0	0	Txm related Acct 456
28	Transmission Rents Received from Electric Properties	I (O)	0	0	Txm related Acct 454-rent
29	Total Revenue Requirements (Line 14 thru 28)		243,441	2,142,485	
III. CURRENT CALENDAR YEAR ESTIMATED INCREMENTAL REVENUE REQUIREMENT					
30	Carrying Charge Factor Base Revenue Requirement Numerator			2,321,639	
31	Post-2003 Enhanced Return Addition to Revenue Requirement			-	
32	Total Post-96 PTF Revenue Requirement			2,321,639	
33	Post-96 PTF Transmission Plant in Service			21,621,455	
34	Post-96 Carrying Charge Factor (Post-96 CCF)			9.9%	
35	Forecasted Post-96 PTF Plant Additions			0	
36	Forecasted Post-96 Localized PTF Plant Additions			0	
37	Forecasted Post-96 Pool-Supported PTF Plant Additions			0	
38	Post-96 Estimated Incremental Revenue Requirement			0	

RNS Rate

Braintree Electric Light Department
FERC Interest Calculation associated with Under / (Over)
True Up and Interest Calculation for 2011

1 2011 Actual Annual RR			230,680	2,111,408	Input Panel Subtotals
2 2011 Est. Transmission Revenue Requirements (as billed)	6/11-05/12	Appendix C	243,441	2,142,485	ATRR - Prior Year
3 True-up (Over)/Under (Line 1 - Line 2)			-12,761	-31,077	

	Overcollection/(Undercollection)
Pre'97	(\$12,761)
Post'96	(\$31,077)

Initial Billing Period	Pre 1997 Balance	Post 1996 Balance	FERC Monthly Interest Rate	Pre 1997 Interest	Post 1996 Interest
June 2011	(\$12,761)	-\$31,077	0.27%	(\$34)	(\$84)
July 2011	(12,795)	-31,161	0.27%	-35	(\$84)
August 2011	(12,795)	-31,161	0.28%	-36	(\$87)
September 2011	(12,795)	-31,161	0.27%	-35	(\$84)
October 2011	(12,900)	-31,416	0.28%	-36	(\$88)
November 2011	(12,900)	-31,416	0.27%	-35	(\$85)
December 2011	(12,900)	-31,416	0.28%	-36	(\$88)
January 2012	(13,007)	-31,677	0.28%	-36	(\$89)
February 2012	(13,007)	-31,677	0.26%	-34	(\$82)
March 2012	(13,007)	-31,677	0.28%	-36	(\$89)
April 2012	(13,114)	-31,937	0.27%	-35	(\$86)
May 2012	(13,114)	-31,937	0.28%	-37	(\$89)
		Total Interest		-\$425	-\$1,036
		True-Up		-\$12,761	-\$31,077
		Total TU & Int		-\$13,186	-\$32,113

Sheet: Input Panel

NEPOOL Tariff Billing
NEPOOL Annual Transmission Revenue Requirements
per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3

PRE 97

Shading denotes an input

Submitted on: 14-May-12

Revenue Requirements for (year): Calendar Year 2011

Customer: Braintree Electric Light Department

Customer's NABs Number: Customer ID: 05

Name of Participant responsible for customer's billing: Braintree Electric Light Department - William Bottiggi

DUNs number of Participant responsible for customer's billing: 17-057-1897

	<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>
Total of Attachment F - Sections A through I =	<u>167,080</u> (a)	<u> </u> (f)
Total of Attachment F - Section J - Support Revenue	<u>0</u> (b)	<u>0</u> (g)
Total of Attachment F - Section K - Support Expense	<u>63,600</u> (c)	<u>0</u> (h)
Total of Attachment F - Section (L through O)	<u>0</u> (d)	<u>0</u> (i)
Sub Total - Sum (A through I) - J + K + (L through O)	<u>230,680</u> (e)=(a)-(b)+(c)+(d)	<u>0</u> (j)
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:		<u>230,680</u> (k) = (e) + (j)
Total of Attachment F - Section J - Pre-97 Support Revenue (from above)		<u>0</u> (b)
Total of Attachment F - Section J - Post-96 Support Revenue (from above-)		<u>0</u> (g)
Total of Attachment F - Section K - Post-96 Support Expense (from above)		<u>0</u> (h)
Voting Share Total for Participant's R Value: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)		<u><u>230,680</u></u> (l)=(k)+(b)+(g)-(h)

Shading denotes an input

		Attachment F		
		Reference	Braintree	Reference
Line No.	I. INVESTMENT BASE	Section:		
1	Transmission Plant	(A)(1)(a)	1,703,903	Worksheet 3a, L10
2	General Plant	(A)(1)(b)	7,410	Worksheet 3a, L11
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3a, L14
4	Total Plant (Lines 1+2+3)		1,711,313	
5	Accumulated Depreciation	(A)(1)(d)	796,749	Worksheet 3a, L19
6	Accumulated Deferred Income Taxes	(A)(1)(e)	0	Worksheet 3a, L24
7	Loss On Reacquired Debt	(A)(1)(f)	0	Worksheet 3a, L26
8	Other Regulatory Assets	(A)(1)(g)	0	Worksheet 3a, L32
9	Net Investment (Line 4-5-6+7+8)		914,564	
10	Prepayments	(A)(1)(h)	131	Worksheet 3a, L34
11	Materials & Supplies	(A)(1)(i)	1,627	Worksheet 3a, L36
12	Cash Working Capital	(A)(1)(j)	9,785	Worksheet 3a, 44
13	Total Investment Base (Line 9+10+11+12)		926,107	
II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	74,089	Worksheet 2a, E56
15	Depreciation Expense	(B)	60,268	Worksheet 4a, L12
16	Amortization of Loss on Reacquired Debt	(C)	0	Worksheet 4a, L14
17	Investment Tax Credit	(D)	0	Worksheet 4a, L16
18	Property Tax Expense	(E)	17,318	Worksheet 4a, L21
19	Payroll Tax Expense	(F)	729	Worksheet 4a, L42
20	Operation & Maintenance Expense	(G)	4,537	Worksheet 4a, L29
21	Administrative & General Expense	(H)	10,139	Worksheet 4a, L40
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	63,600	Worksheet 7, E51
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	0	
28	Transmission Rents Received from Electric Property	(O)	0	
29	Total Revenue Requirements (Line 14 thru 28)		230,680	
			167,080	

Braintree Electric Light Department**Annual Revenue Requirements - 2012
for costs in 2011**

Shading denotes an input

	CAPITALIZATION 12/31/2009	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 109,845,000	100.00%	8.00%	8.00%	
PREFERRED STOCK	0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	0	0.00%	0.00%	0.00%	0.00%
TOTAL INVESTMENT RETURN	\$ 109,845,000	100.00%		8.00%	0.00%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0800

(b) Federal Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / \text{Federal Income Tax Rate}}{1} \right) \times \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}}$$

=
$$\left(\frac{0.0000 + \left(\frac{0 + 0}{926,107} \right)}{1} \right) \times \frac{0}{0}$$

= 0.0000000

(c) State Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / \text{Federal Income Tax Rate}}{1} \right) + \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}} \times \text{State Income Tax Rate}$$

=
$$\left(\frac{0.0000 + \left(\frac{0 + 0}{926,107} \right)}{1} \right) + \frac{0.0000000}{0} \times 0$$

= 0.0000000

(a)+(b)+(c) **Cost of Capital Rate** = 0.0800000

(PTF)

INVESTMENT BASE \$ 926,107 From Worksheet 1

x Cost of Capital Rate 0.0800000

= Investment Return and Income Taxes 74,089 To Worksheet 1

Shading denotes an input

Line No.		(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Mass DTE AR Reference for col (1)
<u>Transmission Plant</u>							
1	Transmission Plant	\$ 24,078,382		24,078,382		1,703,903	Worksheet 5, E12 Page 8B line 29(g)
2	General Plant	\$ 17,262,395	0.6066% (a)	104,714	7.0765%	7,410	
3	Total (line 1+2)			24,183,096		1,711,313	
4	<u>Transmission Plant Held for Future Use</u>	0		0	7.0765%	0	None known
<u>Transmission Accumulated Depreciation</u>							
5	Transmission Accum. Depreciation	11,223,788		11,223,788	7.0765%	794,251	Page 8A, line 31(g) less Page 16, line 31(g) Page 8B, line 29(g) less Page 17, line 29(g)
6	General Plant Accum.Depreciation	5,819,037	0.6066% (a)	35,298	7.0765%	2,498	
7	Total (line 5+6)			11,259,086		796,749	
<u>Transmission Accumulated Deferred Taxes</u>							
8	Accumulated Deferred Taxes (281-283)	0	10.6008% (c)	0	7.0765%	0	None known
9	Accumulated Deferred Taxes (190)	0	10.6008% (c)	0	7.0765%	0	None known
10	Total (line 8+9)			0		0	
11	<u>Transmission loss on Reacquired Debt</u>	0	10.6008% (c)	0	7.0765%	0	None known
<u>Other Regulatory Assets</u>							
12	FAS 106	0	0.6066% (a)	0	7.0765%	0	None known
13	FAS 109	0	10.6008% (c)	0	7.0765%	0	None known
14	Other Regulatory Liabilities (254.DK)	0	10.6008% (c)	0	7.0765%	0	
15	Total (line 12+13+14)	0		0		0	
16	<u>Transmission Prepayments</u>	305,468	0.6066% (a)	1,853	7.0765%	131	Page 10, Line 26 MA DTE
17	<u>Transmission Materials and Supplies</u>	3,791,132	0.6066%	22,997	7.0765%	1,627	Page 10, Line 24 MA DTE
<u>Cash Working Capital</u>							
18	Operation & Maintenance Expense					4,537	Worksheet 1, Line 20
20	Administrative & General Expense					10,139	Worksheet 1, Line 21
21	Transmission Support Expense					63,600	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					78,276	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					9,785	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

Braintree Electric Light Department

		(2)	(4)			
Shading denotes an input						
Line No.	(1) Total	Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Mass DTE AR Reference for col (1)
<u>Depreciation Expense</u>						
1	848,089		848,089	7.0765%	60,015	Page 16, line 31(d)
2	589,317	0.6066% (a)	3,575	7.0765%	253	Page 17, line 29(d)
3			851,664		60,268	
4	0	10.6008% (c)	0	7.0765%	0	None known
5	0	10.6008% (c)	0	7.0765%	0	None known
<u>Property Taxes *</u>						
6	2,183,673	0.106008	231,487	7.0765%	16,381	Page 21, line 33 (b)
7	2,183,673	0.6066% (a)	13,246	7.0765%	937	Page 21, line 33 (b)
8			244,733		17,318	
<u>Transmission Operation and Maintenance</u>						
9	65,558		65,558	0.070765	4,639	Page 40, line 50(b)
10	0		0	0.070765	0	Page 40, line 38(b)
11	0		0	0.070765	0	Page 40, line 34(b)
12	1,447		1,447	0.070765	102	Page 40, line 35(b) 40(b)
13	64,111		65,558	7.0765%	4,537	
<u>Transmission Administrative and General</u>						
14	9,387,652					Page 42, line 5(b)
15	863,889					Page 41, line 47(b)
16	0					Page 41, line 50(b)
17	966					assumed none
18	8,522,797	0.6066% (a)	51,699	7.0765%	3,658	
19	863,889	10.6008% (c)	91,579	7.0765%	6,481	
20	0	10.6008% (c)	0	7.0765%	0	
21	0	10.6008% (c)	0	7.0765%	0	
22	9,386,686		143,278		10,139	
23	1,698,800	0.6066% (a)	10,305	7.0765%	729	Per company workpapers

- (a) Worksheet 5 of 8, line 11
(b) Worksheet 5 of 8, line 3
(c) Worksheet 5 of 8, line 16

Shading denotes an input

<u>Line No.</u>			<u>Mass DTE AR Reference</u>
	<u>PTF Transmission Plant Allocation Factor</u>	Braintree	
1	PTF Transmission Investment	1,703,903	Per Braintree Workpapers
2	Total Transmission Investment	24,078,382	Page 8A, line 31(g)
3	Percent Allocation (Line 1/Line 2)	7.0765%	
	<u>Transmission Wages and Salaries Allocation Factor</u>		
4	Direct Transmission Wages and Salaries	50,702	See BELD General Ledger
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 of 7
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	50,702	
7	Total Wages and Salaries	9,442,335	Page 42, line 24 (c)
8	Administrative and General Wages and Salaries	1,083,381	Page 41, line 43(b)
9	Affiliated Company Wages and Salaries less A&G	0	Worksheet 6
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	8,358,954	
11	Percent Allocation (Line 6/Line 10)	0.6066%	
	<u>Plant Allocation Factor</u>		
12	Total Transmission Investment	24,078,382	Line 2
13	<i>plus Transmission-Related General Plant (Line 2 of Wkst. 3)</i>	104,714	Worksheet 3, Line 2
14	<i>= Revised Numerator (Line 12 + Line 13)</i>	24,183,096	
15	Total Plant in Service	228,125,439	Page 8B, line 30 (g)
16	Percent Allocation (Line 14 / Line 15)	10.6008%	

Affiliated Company Wages and Salaries

Shading denotes an input

Line		Braintree
"Affiliated" Transmission Wages and Salaries #560 - 573		
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11 = 1 thru 10	Total Transmission	0
12 = Total "Affiliated" Wages and Salaries		0
Less "Affiliated" Administrative and General Salaries #920 - 935		
13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
21 = 13 thru 20		0
22 = 12 less 21	Total "Affiliated" less A&G	0

Sheet: Worksheet 7

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	FERC Form 1	TOTAL	
			Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	332.(g); [332.1(g) for HWP]		\$1,414
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			\$8,602
	Comerford 115 kV Substation			
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	332.1(g); [332(g) for CL&P]		\$20,378
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 394 line	332(g)		\$2,596
NEP	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			\$2,453
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310 line	330.1(n)		
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
Seabrook				\$28,157
Total =			0	63,600

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

Sheet: Input Panel

NEPOOL Tariff Billing
NEPOOL Annual Transmission Revenue Requirements
per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3

Shading denotes an input

POST 96

Submitted on: 14-May-12

Revenue Requirements for (year): Calendar Year 2011

Customer: Braintree Electric Light Department

Customer's NABs Number: Customer ID: 05

Name of Participant responsible for customer's billing: Braintree Electric Light Department - William Bottiggi

DUNs number of Participant responsible for customer's billing: 17-057-1897

	<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>
Total of Attachment F - Sections A through I =	<u>(a)</u>	<u>2,111,408 (f)</u>
Total of Attachment F - Section J - Support Revenue	<u>0 (b)</u>	<u>0 (g)</u>
Total of Attachment F - Section K - Support Expense	<u>(c)</u>	<u>0 (h)</u>
Total of Attachment F - Section (L through O)	<u>0 (d)</u>	<u>0 (i)</u>
Sub Total - Sum (A through I) - J + K + (L through O)	<u>0 (e)=(a)-(b)+(c)+(d)</u>	<u>2,111,408 (j)</u>
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:		<u>2,111,408 (k) = (e) + (j)</u>
Total of Attachment F - Section J - Pre-97 Support Revenue (from above)		<u>0 (b)</u>
Total of Attachment F - Section J - Post-96 Support Revenue (from above-)		<u>0 (g)</u>
Total of Attachment F - Section K - Post-96 Support Expense (from above)		<u>0 (h)</u>
Voting Share Total for Participant's R Value: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)		<u><u>2,111,408 (l)=(k)+(b)+(g)-(h)</u></u>

Calendar Year 2011

Shading denotes an input

		Attachment F		
		Reference	Braintree	Reference
Line No.	I. INVESTMENT BASE	Section:		
1	Transmission Plant	(A)(1)(a)	21,621,455	Worksheet 3a, L10
2	General Plant	(A)(1)(b)	94,029	Worksheet 3a, L11
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3a, L14
4	Total Plant (Lines 1+2+3)		21,715,484	
5	Accumulated Depreciation	(A)(1)(d)	10,109,902	Worksheet 3a, L19
6	Accumulated Deferred Income Taxes	(A)(1)(e)	0	Worksheet 3a, L24
7	Loss On Reacquired Debt	(A)(1)(f)	0	Worksheet 3a, L26
8	Other Regulatory Assets	(A)(1)(g)	0	Worksheet 3a, L32
9	Net Investment (Line 4-5-6+7+8)		11,605,582	
10	Prepayments	(A)(1)(h)	1,664	Worksheet 3a, L34
11	Materials & Supplies	(A)(1)(i)	20,650	Worksheet 3a, L36
12	Cash Working Capital	(A)(1)(j)	23,254	Worksheet 3a, 44
13	Total Investment Base (Line 9+10+11+12)		11,651,150	
II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	932,092	Worksheet 2a, E56
15	Depreciation Expense	(B)	764,761	Worksheet 4a, L12
16	Amortization of Loss on Reacquired Debt	(C)	0	Worksheet 4a, L14
17	Investment Tax Credit	(D)	0	Worksheet 4a, L16
18	Property Tax Expense	(E)	219,268	Worksheet 4a, L21
19	Payroll Tax Expense	(F)	9,253	Worksheet 4a, L42
20	Operation & Maintenance Expense	(G)	57,570	Worksheet 4a, L29
21	Administrative & General Expense	(H)	128,464	Worksheet 4a, L40
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	0	Worksheet 7, E51
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	0	
28	Transmission Rents Received from Electric Property	(O)	0	
29	Total Revenue Requirements (Line 14 thru 28)		2,111,408	

Braintree Electric Light Department**Annual Revenue Requirements - 2012****Calendar Year 2011**

Shading denotes an input

	CAPITALIZATION 12/31/2006	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 109,845,000	100.00%	8.00%	8.00%	
PREFERRED STOCK	0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	0	0.00%	0.00%	0.00%	0.00%
TOTAL INVESTMENT RETURN	\$ 109,845,000	100.00%		8.00%	0.00%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0800

(b) Federal Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right)}{1} \right) \times \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}}$$

=
$$\left(\frac{0.0000 + \left(\frac{0 + 0}{11,651,150} \right)}{1} \right) \times \frac{0}{0}$$

= 0.0000000

(c) State Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right)}{1} \right) + \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}} \times \text{State Income Tax Rate}$$

=
$$\left(\frac{0.0000 + \left(\frac{0 + 0}{11,651,150} \right)}{1} \right) + \frac{0.0000000}{0} \times 0$$

= 0.0000000

(a)+(b)+(c) **Cost of Capital Rate** = 0.0800000

(PTF)

INVESTMENT BASE \$ 11,651,150 From Worksheet 1

x Cost of Capital Rate 0.0800000

= Investment Return and Income Taxes 932,092 To Worksheet 1

Braintree Electric Light Department

Calendar Year 2011

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Mass DTE AR Reference for col (1)
<u>Transmission Plant</u>						
1	\$ 24,078,382		24,078,382		21,621,455	Worksheet 5, E12 Page 8B line 29(g)
2	\$ 17,262,395	0.6066% (a)	104,714	89.7961%	94,029	
3			24,183,096		21,715,484	
4	0		0	89.7961%	0	None known
<u>Transmission Accumulated Depreciation</u>						
5	11,223,434		11,223,434	89.7961%	10,078,206	Page 8A, line 31(g) less Page 16, line 31(g)
6	5,819,037	0.6066% (a)	35,298	89.7961%	31,696	Page 8B, line 29(g) less Page 17, line 29(g)
7			11,258,732		10,109,902	
<u>Transmission Accumulated Deferred Taxes</u>						
8	0	10.5757% (c)	0	89.7961%	0	None known
9	0	10.5757% (c)	0	89.7961%	0	None known
10			0		0	
11	0	10.5757% (c)	0	89.7961%	0	None known
<u>Other Regulatory Assets</u>						
12	0	0.6066% (a)	0	89.7961%	0	None known
13	0	10.5757% (c)	0	89.7961%	0	None known
14	0	10.5757% (c)	0	89.7961%	0	
15	0		0		0	
16	305,468	0.6066% (a)	1,853	89.7961%	1,664	Page 10, Line 26 MA DTE
17	3,791,132	0.6066%	22,997	89.7961%	20,650	Page 10, Line 24 MA DTE
<u>Cash Working Capital</u>						
19					57,570	Worksheet 1, Line 20
20					128,464	Worksheet 1, Line 21
21					0	Worksheet 1, Line 24
22					186,034	
23					0.125	x 45 / 360
24					23,254	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

Braintree Electric Light Department

Calendar Year 2011

(2)

(4)

Shading denotes an input

Line No.	(1) Total	Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Mass DTE AR Reference for col (1)
<u>Depreciation Expense</u>						
1	848,089		848,089	89.7961%	761,551	Page 16, line 31(d)
2	589,317	0.6066% (a)	3,575	89.7961%	3,210	Page 17, line 29(d)
3			851,664		764,761	
4	0	10.5757% (c)	0	89.7961%	0	None known
5	0	10.5757% (c)	0	89.7961%	0	None known
<u>Property Taxes *</u>						
6	2,183,673	0.105757	230,939	89.7961%	207,374	Page 21, line 33 (b)
7	2,183,673	0.6066% (a)	13,246	89.7961%	11,894	Page 21, line 33 (b)
8			244,185		219,268	
<u>Transmission Operation and Maintenance</u>						
9	65,558		65,558	0.897961	58,869	Page 40, line 50(b)
10	0		0	0.897961	0	Page 40, line 38(b)
11	0		0	0.897961	0	Page 40, line 34(b)
12	1,447		1,447	0.897961	1,299	Page 40, line 35(b) 40(b)
13	64,111		65,558	89.7961%	57,570	
<u>Transmission Administrative and General</u>						
14	9,387,652					Page 42, line 5(b)
15	863,889					Page 41, line 47(b)
16	0					Page 41, line 50(b)
17	966					assumed none
18	8,522,797	0.6066% (a)	51,699	89.7961%	46,424	
19	863,889	10.5757% (c)	91,362	89.7961%	82,040	
20	0	10.5757% (c)	0	89.7961%	0	
21	0	10.5757% (c)	0	89.7961%	0	
22	9,386,686		143,061		128,464	
23	1,698,800	0.6066% (a)	10,305	89.7961%	9,253	Per company workpapers

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

Shading denotes an input

Calendar Year 2011

Line No.			Mass DTE AR Reference
	<u>PTF Transmission Plant Allocation Factor</u>	Braintree	
1	PTF Transmission Investment	21,621,455	Per Braintree Workpapers
2	Total Transmission Investment	24,078,382	Page 8A, line 31(g)
3	Percent Allocation (Line 1/Line 2)	89.7961%	
	<u>Transmission Wages and Salaries Allocation Factor</u>		
4	Direct Transmission Wages and Salaries	50,702	See BELD General Ledger
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 of 7
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	50,702	
7	Total Wages and Salaries	9,442,335	Page 42, line 24 (c)
8	Administrative and General Wages and Salaries	1,083,381	Page 41, line 43(b)
9	Affiliated Company Wages and Salaries less A&G	0	Worksheet 6
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	8,358,954	
11	Percent Allocation (Line 6/Line 10)	0.6066%	
	<u>Plant Allocation Factor</u>		
12	Total Transmission Investment	24,078,382	Line 2
13	plus Transmission-Related General Plant (Line 2 of Wkst. 3)	47,416	Worksheet 3, Line 2
14	= Revised Numerator (Line 12 + Line 13)	24,125,798	
15	Total Plant in Service	228,125,439	Page 8B, line 30 (g)
16	Percent Allocation (Line 14 / Line 15)	10.5757%	

Affiliated Company Wages and Salaries

 Shading denotes an input

Calendar Year 2011

Line		Braintree
"Affiliated" Transmission Wages and Salaries #560 - 573		
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11 = 1 thru 10	Total Transmission	0
12 = Total "Affiliated" Wages and Salaries		0
Less "Affiliated" Administrative and General Salaries #920 - 935		
13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
21 = 13 thru 20		0
22 = 12 less 21	Total "Affiliated" less A&G	0

BRAINTREE

PTF Revenue Requirements

Sheet: Worksheet 7

Calendar Year 2011

Worksheet 7 of 7

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	FERC Form 1	TOTAL	
			Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	332.(g); [332.1(g) for HWP]		0
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			0
	Comerford 115 kV Substation			
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	332.1(g); [332(g) for CL&P]		0
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 394 line	332(g)		0
	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			0
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310 line	330.1(n)		
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
Seabrook				0
Total =			0	0

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

ISO-NE Tariff Billing
PTO Annual Transmission Revenue Requirements
per OATT Attachment F

Submitted on:	May 14, 2012
Revenue Requirements for (test year):	Calendar Year 2011
Rates Effective for the period:	June 1, 2012
through:	May 31, 2013
Customer:	Central Maine Power Company
Customer's NABs Number:	06
Name of Participant responsible for customer's billing:	Central Maine Power Company
DUNS number of Participant responsible for customer's billing:	006948954

	<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>
Total of Attachment F - Sections A through I	\$ 15,815,614 (a)	\$ 113,590,366 (f)
Total of Attachment F - Section J - Support Revenue	309,217 (b)	- (g)
Total of Attachment F - Section K - Support Expense	691,571 (c)	- (h)
Total of Attachment F - Section (L through O)	(528,253) (d)	(1,191,809) (i)
Sub Total - Sum (A through I) - J + K + (L through O)	15,669,715 (e)=(a)-(b)+(c)+(d)	112,398,557 (j)
Forecasted Transmission Revenue Requirements (per Appendix C to Attachment F Implementation Rule)	N/A	54,449,814 (k)
Annual True-up (per Appendix C to Attachment F Implementation Rule)	(1,618,831) (l)	(33,676,581) (m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)	\$ 14,050,884 (n)=(e)+(l)	\$ 133,171,791 (o)=(j)+(k)+(m)
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements & Post-96 Revenue Requirements Subtotals, Forecasted Revenue Requirements and True-ups (including interest)	<u>\$ 147,222,675</u> (p) = (n)+(o)	

CMP
Annual Revenue Requirements of PTF Facilities
2011

Line No.	I. INVESTMENT BASE	Attachment F Reference				
			PRE97	POST 1996	TOTAL	
		<i>Section:</i>				
1	Transmission Plant	(A)(1)(a)	\$ 108,694,490	245,229,075	\$	353,923,565
2	General Plant	(A)(1)(b)	1,891,274	4,266,961		6,158,235
3	Plant Held For Future Use	(A)(1)(c)	640,952	1,446,072		2,087,024
4	Total Plant (Lines 1+2+3)		111,226,716	250,942,108		362,168,824
5	Accumulated Depreciation	(A)(1)(d)	(34,780,771)	(78,469,969)		(113,250,740)
6	Accumulated Deferred Income Taxes	(A)(1)(e)	(16,490,396)	(37,204,492)		(53,694,888)
7	Loss On Reacquired Debt	(A)(1)(f)	181,945	410,492		592,437
8	Other Regulatory Assets	(A)(1)(g)	103,358	233,190		336,548
9	Net Investment (Line 4+5+6+7+8)		60,240,852	135,911,329		530,043,437
10	Prepayments	(A)(1)(h)	31,952	72,088		104,040
11	Materials & Supplies	(A)(1)(i)	721,028	1,626,733		2,347,761
12	Cash Working Capital	(A)(1)(j)	398,358	790,918		1,189,276
13	MPRP CWIP	II (A)(1)(k)	-	469,939,977		469,939,977
14	Total Investment Base (Line 9+10+11+12+13)		\$ 61,392,190	\$ 608,341,045	\$	1,003,624,491
	II. <u>REVENUE REQUIREMENTS</u>					
15	Investment Return and Income Taxes	(A)	\$ 9,182,804	\$ 98,625,879	\$	107,808,683
16	Depreciation Expense	(B)	2,624,601	5,921,442		8,546,043
17	Amortization of Loss on Reacquired Debt	(C)	41,903	94,539		136,442
18	Investment Tax Credit	(D)	(42,120)	(95,029)		(137,149)
19	Property Tax Expense	(E)	1,203,915	2,716,189		3,920,104
20	Payroll Tax Expense	(F)	-	-		-
21	Operation & Maintenance Expense	(G)	2,405,294	5,426,659		7,831,953
22	Administrative & General Expense	(H)	399,217	900,687		1,299,904
23	Transmission Related Integrated Facilities Charge	(I)	-	-		-
24	Transmission Support Revenue	(J)	(309,217)	-		(309,217)
25	Transmission Support Expense	(K)	691,571	-		691,571
26	Transmission Related Expense from Generators	(L)	-	-		-
27	Transmission Related Taxes and Fees Charge	(M)	-	-		-
28	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(528,253)	(1,191,809)		(1,720,062)
29	Transmission Rents Received from Electric Property	(O)	-	-		-
30	Total RNS Revenue Requirements before Forecast, Annual True-up and Assoc. Interest (Line 15 thru 29)		\$ 15,669,715	\$ 112,398,557	\$	128,068,272

CMP
Annual Revenue Requirements of PTF Facilities
2010

Line No.	I. INVESTMENT BASE	Attachment F Reference	PRE 97	POST 1996	TOTAL
		Section:			
1	Transmission Plant	(A)(1)(a)	\$ 109,971,197	\$ 197,508,461	\$ 307,479,658
2	General Plant	(A)(1)(b)	2,203,308	3,957,150	6,160,458
3	Plant Held For Future Use	(A)(1)(c)	861,600	1,547,437	2,409,037
4	Total Plant (Lines 1+2+3)		113,036,105	203,013,048	316,049,153
5	Accumulated Depreciation	(A)(1)(d)	40,413,155	72,582,176	112,995,331
6	Accumulated Deferred Income Taxes	(A)(1)(e)	10,892,586	19,563,124	30,455,710
7	Loss On Reacquired Debt	(A)(1)(f)	249,092	447,369	696,461
8	Other Regulatory Assets	(A)(1)(g)	192,991	346,612	539,603
9	Net Investment (Line 4-5-6+7+8)		62,172,447	111,661,729	173,834,176
10	Prepayments	(A)(1)(h)	56,349	101,203	157,552
11	Materials & Supplies	(A)(1)(i)	731,927	1,314,544	2,046,471
12	Cash Working Capital	(A)(1)(j)	519,794	898,333	1,418,127
13	MPRP CWIP	II (A)(1)(k)	-	182,322,304	182,322,304
14	Total Investment Base (Line 9+10+11+12+13)		\$ 63,480,517	\$ 296,298,113	\$ 359,778,630
II. REVENUE REQUIREMENTS					
15	Investment Return and Income Taxes	(A)	\$ 9,796,301	\$ 49,248,044	\$ 59,044,345
16	Depreciation Expense	(B)	2,894,263	5,198,108	8,092,371
17	Amortization of Loss on Reacquired Debt	(C)	46,628	83,745	130,373
18	Investment Tax Credit	(D)	(46,870)	(84,179)	(131,049)
19	Property Tax Expense	(E)	1,155,258	2,074,848	3,230,106
20	Payroll Tax Expense	(F)	-	-	-
21	Operation & Maintenance Expense	(G)	3,180,784	5,712,700	8,893,484
22	Administrative & General Expense	(H)	820,691	1,473,964	2,294,655
23	Transmission Related Integrated Facilities Charge	(I)	-	-	-
24	Transmission Support Revenue	(J)	(581,751)	-	(581,751)
25	Transmission Support Expense	(K)	738,625	-	738,625
26	Transmission Related Expense from Generators	(L)	-	-	-
27	Transmission Related Taxes and Fees Charge	(M)	-	-	-
28	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(767,588)	(1,378,588)	(2,146,176)
29	Transmission Rents Received from Electric Property	(O)	-	-	-
29	Total RNS Revenue Requirements before Forecast, Annual True-up and Assoc. Interest (Line 14 thru 28)		\$ 17,236,341	\$ 62,328,642	\$ 79,564,983
30	Forecasted PTF Revenue Requirements - 2011		-	82,660,470	82,660,470
31	Total RNS Rev Req'ts subject to Annual True-up		\$ 17,236,341	\$ 144,989,112	\$ 162,225,453
32	PY true-up		(1,610,066)	(1,682,144)	(3,292,210)
33	Total RNS-6/1/11-5/31/12		\$ 15,626,275	\$ 143,306,968	\$ 158,933,243

CMP
Transmission Revenue Requirements of PTF Facilities
2011 True-up

I. APPENDIX C - ANNUAL TRUE-UP		Rate Year	PRE97	POST 1996	Total	Reference
1	ATRR for True-up = 2011 Actual	6/1/12-5/31/2013	\$ 15,669,715	\$ 112,398,557	\$ 128,068,272	Summary 6-1-12_5-31-13, line 30
2	ATRR subject to True-up = '10 TY + '11 Forecast (as billed)	6/1/11-5/31/2012	<u>\$ 17,236,341</u>	<u>\$ 144,989,112</u>	<u>\$ 162,225,453</u>	Summary 6-1-11_5-31-12, line 31
3	Annual True-up (Line 1 - Line 2)		<u>\$ (1,566,626)</u>	<u>\$ (32,590,555)</u>	<u>\$ (34,157,181)</u>	

Central Maine Power Company
FERC Interest Calculation associated with Annual True Up
PTF Transmission Revenue Requirements

Pre1997 Post1996	Under / (Overcollection)					
	(1,566,626)					
	(32,590,555)					
			FERC Monthly Interest Rate	PRE97 Interest	POST 1996 Interest	Total PTF
Initial Billing Period	PRE97 Balance	POST 1996 Balance				
June 2011	(1,566,626)	(32,590,555)	0.27%	(4,230)	(87,994)	
July 2011	(1,570,856)	(32,678,549)	0.27%	(4,241)	(88,232)	
August 2011	(1,570,856)	(32,678,549)	0.28%	(4,398)	(91,500)	
September 2011	(1,570,856)	(32,678,549)	0.27%	(4,241)	(88,232)	
October 2011	(1,583,737)	(32,946,513)	0.28%	(4,434)	(92,250)	
November 2011	(1,583,737)	(32,946,513)	0.27%	(4,276)	(88,956)	
December 2011	(1,583,737)	(32,946,513)	0.28%	(4,434)	(92,250)	
January 2012	(1,596,882)	(33,219,969)	0.28%	(4,471)	(93,016)	
February 2012	(1,596,882)	(33,219,969)	0.26%	(4,152)	(86,372)	
March 2012	(1,596,882)	(33,219,969)	0.28%	(4,471)	(93,016)	
April 2012	(1,609,976)	(33,492,373)	0.27%	(4,347)	(90,429)	
May 2012	(1,609,976)	(33,492,373)	0.28%	(4,508)	(93,779)	
Total Interest				\$ (52,205)	\$ (1,086,026)	\$ (1,138,231)
Annual True-Up				(1,566,626)	(32,590,555)	(34,157,181)
Total ATU & Int				\$ (1,618,831)	\$ (33,676,581)	\$ (35,295,412)

**CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

			Attachment F					
			Reference					Reference
Line No.	II. INVESTMENT BASE		Section:					
1	Transmission Plant	II (A)(1)(a)	\$ 108,694,490					Worksheet 3, line 1 column 5
2	General Plant	II (A)(1)(b)	1,891,274					Worksheet 3, line 2 column 5
3	Plant Held For Future Use	II (A)(1)(c)	640,952					Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		111,226,716					
5	Accumulated Depreciation	II (A)(1)(d)	(34,780,771)					Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	II (A)(1)(e)	(16,490,396)					Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	II (A)(1)(f)	181,945					Worksheet 3, line 11 column 5
8	Other Regulatory Assets	II (A)(1)(g)	103,358					Worksheet 3, line 14 column 5
9	Net Investment (Line 4+5+6+7+8)		60,240,852					
10	Prepayments	II (A)(1)(h)	31,952					Worksheet 3, line 15 column 5
11	Materials & Supplies	II (A)(1)(i)	721,028					Worksheet 3, line 16 column 5
12	Cash Working Capital	II (A)(1)(j)	398,358					Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		\$ 61,392,190					
	II. REVENUE REQUIREMENTS							
14	Investment Return and Income Taxes	II (A)	\$ 9,182,804					Worksheet 2
15	Depreciation Expense	II (B)	2,624,601					Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	II (C)	41,903					Worksheet 4, line 4 column 5
17	Investment Tax Credit	II (D)	(42,120)					Worksheet 4, line 5 column 5
18	Municipal Taxes	II (E)	1,203,915					Worksheet 4, line 8 column 5
19	Payroll Taxes	II (F)	-					Worksheet 4, line 9 column 5
20	Operation & Maintenance Expense	II (G)	2,405,294					Worksheet 4, line 14 column 5
21	Administrative & General Expense	II (H)	399,217					Worksheet 4, line 18 column 5
22	Transmission Related Integrated Facilities Charge	II (I)	-					
23	Transmission Support Revenue	II (J)	(309,217)					Worksheet 7, line 11 column a
24	Transmission Support Expense	II (K)	691,571					Worksheet 7, line 11 column b
25	Transmission Related Expense from Generators	II (L)	-					
26	Taxes and Fees	II (M)	-					
27	Revenues for TOUT Transmission Service	II (N)	(528,253)					Worksheet 20
28	Transmission Rents Received from Electric Property	II (O)	-					
29	Total Revenue Requirements (Line 14 thru 28)		\$ 15,669,715					

**CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

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**CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

			(2)		(4)					RNS Rate			
			Wage/Plant	(3) = (1)*(2)	PTF	(5) = (3)*(4)				Worksheet or			
Line		(1)	Allocation	Transmission	Allocation	PTF			FERC Form 1				
No.		Total	Factors	Allocated	Factor (b)	Allocated			Reference for col (1) or (5)				
	<u>Transmission Plant</u>												
1	Transmission Plant	-		-		108,694,490	(d)	w/s 5, line 1					
2	General Plant	174,346,071	5.7481%	(a) 10,021,586	18.8720%	1,891,274		w/s 17, line 5					
3	Total (line 1+2)			10,021,586		110,585,764							
4	<u>Transmission Plant Held for Future Use</u>	3,396,312		3,396,312	18.8720%	640,952		w/s 17, line 9					
	<u>Transmission Accumulated Depreciation</u>												
5	Transmission Accum. Depreciation	(179,841,959)		(179,841,959)	18.8720%	(33,939,774)		w/s 17, line 4					
6	General Plant Accum. Depreciation	(77,526,843)	5.7481%	(a) (4,456,320)	18.8720%	(840,997)		w/s 17, line 7					
7	Total (line 6+7)	(257,368,802)		(184,298,279)		(34,780,771)							
	<u>Transmission Accumulated Deferred Taxes</u>												
8	Accumulated Deferred Taxes (281-283)	(128,790,829)		(128,790,829)	18.8720%	(24,305,405)		See p. 450 notes for pages 274 & 276					
9	Accumulated Deferred Taxes (190)	41,410,601		41,410,601	18.8720%	7,815,009		w/s 21, line 2					
10	Total (line 8+9)	(87,380,228)		(87,380,228)		(16,490,396)							
11	<u>Unamortized loss on Reacquired Debt</u>	3,088,334	31.2175%	(c) 964,101	18.8720%	181,945		Page 111.81c					
	<u>Other Regulatory Assets</u>												
12	FAS 106	9,528,029	5.7481%	(a) 547,681				Page 232.1, line 18f					
13	FAS 109	-						DITs functionalized in FF 1 excluding FAS109 DITs, therefore the 109 reg asset is properly excluded.					
14	Total (line 12+13)	9,528,029		547,681	18.8720%	103,358							
15	<u>Transmission Prepayments</u>	2,945,473	5.7481%	(a) 169,309	18.8720%	31,952		FF 1 111.57c					
16	<u>Transmission Materials and Supplies</u>	3,820,623		3,820,623	18.8720%	721,028		See note for page 227.12c on Page 450					
17	<u>Cash Working Capital</u>												
18	Operation & Maintenance Expense					2,405,294		Worksheet 1, Line 20					
19	Administrative & General Expense					399,217		Worksheet 1, Line 21					
20	Net Transmission Support Expense					382,354		Worksheet 7, Line 13b					
21	Subtotal (line 18+19+20)					3,186,865							
22						0.125		x 45 / 360					
23	Total (line 21 * line 22)					398,358							
	(a) Worksheet 5 of 8, line 11												
	(b) Worksheet 5 of 8, line 3												
	(c) Worksheet 5 of 8, line 16												
	(d) EHV/LV PTF Facilities												

**CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

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**CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

					RNS Rate
					Worksheet or
Line					FERC Form 1
No.					Reference
	<u>PTF Transmission Plant Allocation Factor</u>				
			Pre 1997		
1	PTF Transmission Investment		108,694,490		w/s 15
2	Total Transmission Investment		575,956,834		w/s 15 & w/s 17 line 3
3	Percent Allocation (line 1/2)		18.8720%		
	<u>Transmission Wages and Salaries Allocation Factor</u>				
4	Direct Transmission Wages and Salaries		2,284,985		w/s 17, line 1
5	Affiliated Company Transmission Wages and Salaries		-		
6	Total Transmission Wages and Salaries (line 4+ 5)		2,284,985		
7	Total Wages and Salaries		44,543,516		Page 354.28b
8	Administrative and General Wages and Salaries		4,791,627		Page 354.27b
9	Affiliated Company Wages and Salaries less A&G		-		
10	Total Wages and Salaries net of A&G (line 7 - 8 + 9)		39,751,889		
11	Percent Allocation (line 6/10)		5.7481%		
	<u>Plant Allocation Factor</u>				
12	Total Transmission Investment (excluding capital leases)		575,956,834		ws 5 line 2
13	Transmission Related General Plant		10,021,586		ws 3 line 2, col. 3
14	Total Transmission Related Plant		585,978,420		
15	Total Electric Plant in Service (excludes capital leases)		1,877,082,238		Page 207.104g
16	Percent Allocation (line 14/15)		31.2175%		

**CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

Affiliated Company Wages and Salaries								
Line								
"Affiliated" Transmission Wages and Salaries				Transmission Wages by 3 digit FERC				
#560 - 573								
				560	270,006			
1	560		-	561-561.4	1,812,200	w/s 17 line 1b		
				561.5-561.8	73,252			
2	562		-	562	475,811			
3	564		-	563	9,573			
4	566		-	564	602			
5	568		-	566	568,259			
				567	-			
6	569		-	568	151,334			
7	570		-	569	40,471			
8	571		-	570	450,430			
9	572		-	571	217,851			
10	573		-	572	27,396			
11 = 1 thru 10	Total Transmission		-	573	-			
					4,097,185	w/s 17, line 1a		
12 = Total "Affiliated" Wages and Salaries				-				
Less "Affiliated" Administrative and General Salaries								
#920 - 935								
13	920		-					
14	921		-					
15	923		-					
16	925		-					
17	926		-					
18	928		-					
19	930		-					
20	935		-					
21 = 13 thru 20			-					
22 = 12 less 21	Total "Affiliated" less A&G		-	To Worksheet 5				

**CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

			CENTRAL MAINE POWER CO.		
	Participant	PTF Supporting Facilities	Revenues (a)	Expenses (b)	
1	NSTAR:	HQ Phase II - AC in MA		32,348	1
2	Central Maine Power:	345 kV Buxton-South Gorham 386 line	95,646		2
3		115 kV Wyman 164-167 lines	207,627		3
4		115 kV Maine Yankee transmission	-		4
5		50% of double steel towers # 30-46 (sec 375)	5,944		5
6					6
7	New England Power:	Chester SVC		195,473	7
8		HQ Phase II - AC in MA		463,750	8
9					9
10					10
11		Total =	309,217	691,571	11
12					12
13		Net Support (line 11b - 11a)		382,354	13
	RNS Rate worksheet reference: col a - w/s 10, col b - w/s 11				
	<i>Input Revenues associated with the PTF Supporting Facilities in column (a) and expenses associated with the facilities in column (b). The totals are then linked to Worksheet 1, Lines 24 and 25.</i>				

**CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

	Summary of CMP System												
	Monthly Coincident Peaks												
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Average
	* Monthly	* Monthly	* Monthly	* Monthly	* Monthly	* Monthly	* Monthly	* Monthly	* Monthly	* Monthly	* Monthly	* Monthly	* Monthly Average
Network Load Customer	Network Load	Network Load	Network Load	Network Load	Network Load	Network Load	Network Load	Network Load	Network Load	Network Load	Network Load	Network Load	Network Load
	(kW)	(kW)	(kW)	(kW)	(kW)	(kW)	(kW)	(kW)	(kW)	(kW)	(kW)	(kW)	(kW)
Central Maine Power	1,393,739	1,314,320	1,256,723	1,261,789	1,189,830	1,314,292	1,586,417	1,355,581	1,260,884	1,272,624	1,261,450	1,357,663	1,318,776
Fox Island (NP)	1,830	1,514	1,455	1,225	1,323	1,064	1,750	1,770	1,940	1,560	1,480	1,730	1,553
Kennebunk (NP)	18,263	17,426	15,961	14,952	14,028	16,815	21,410	16,830	15,600	14,570	15,820	17,110	16,565
Gates Formed Fiber (NP)	1,942	1,801	1,659	1,700	1,841	1,736	2,000	-	-	-	-	-	1,057
Madison Electric Works	6,057	5,874	5,138	4,830	4,125	4,649	5,210	4,710	4,480	4,520	5,320	5,720	5,053
FPL-Madison Paper	9,978	20,556	16,308	16,164	27,228	21,738	16,400	31,920	29,390	34,020	19,470	29,240	22,701
Westbrook Energy Center	-	-	-	-	-	-	-	-	-	-	-	-	-
FPL Energy	57	46	66	-	-	9	73	99	16	16	-	47	36
Total	1,431,866	1,361,537	1,297,310	1,300,660	1,238,375	1,360,303	1,633,260	1,410,910	1,312,310	1,327,310	1,303,540	1,411,510	1,365,741

**CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

	Acc't	Description	Amount	
1	920	Administrative and General Salaries	6,838,260	
2	921	Office Supplies and Expenses	2,612,247	
3	922	Less Administrative Expenses Transferred	(490,590)	
4	923	Outside Services	22,771,469	
5	924	Property Insurance	290,630	
6	925	Injuries and Damages	2,312,523	
7	926	Employee Pensions and Benefits	(7,064,577)	
8	928	Regulatory Commissions Expense	4,728,904	-
9	930.1	General Advertising	1,628,798	
10	930.2	Miscellaneous General Expense	1,582,968	
11	931	Rents	921,706	
12	935	Maintenance of General Plant	1,785,722	
13		Total Admin & Gen'l Exp.	37,918,060	Page 323.197b
14		FERC assessments - Transmission (directly assigned)	676,625	to worksheet 4, line 17, column 1
15		FERC assessments - subject to plant allocation factor	-	FF1 page 350.d
16		TOTAL FERC ASSESSMENTS (14+15)	676,625	FF1 page 350.d
17		State assessments - Transmission (directly assigned)	54,510	FF1 page 350.d
18		Total State Assessments	4,052,279	FF1 page 350.d
19	928	Total Regulatory Commissions Expense: (16+18) & from line 8	4,728,904	FF1 page 350.d, line 46
20		General Advertising - Transmission related	-	
21		Non-Transmission related General Advertising Exp.	1,628,798	line 9 above
22	930.1	Total General Advertising Exp. (line 9)	1,628,798	
Summary of Attachment F treatment of A&G				
23		Total A&G (line 13)	37,918,060	
24	924	less Property Insurance (line 5)	290,630	
25	926	less pension credit directly assigned to T&D	(8,095,198)	MPUC Docket Nos. 2007-215/2008-111
26	928	less Regulatory Commissions Exp. (line 19)	4,728,904	
27	930.1	less Non-Trans. General Advertising Exp. (line 9)	1,628,798	
28	920-935	less EPRI Expenses	-	
29		A&G subject to Wages and Salaries Allocation Factor:	39,364,926	to worksheet 4, line 15, column 1
30		Property Insurance (line 5)	290,630	
31		Regulatory Commissions Exp. - FERC assessments (line 15)	-	
32		Total A&G subject to Plant Allocation Factor	290,630	to worksheet 4, line 16, column 1
Items Directly Assigned to Transmission				
33	926010	MRFV - transmission only portion of pension credit	(969,202)	MPUC Docket Nos. 2007-215/2008-111
34		State assessments - Transmission (directly assigned) (Line 17 above)	54,510	
35		FERC Reg Comm Exp - Trans (directly assigned) (Line 14 above)	676,625	
36		total to w/s 4, line 17	(238,067)	w/s 4, line 17

**CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

	Party Billed	Facility/Nature of Revenues	RNS Rate Worksheet Reference	PTF	Non-PTF	Total	FERC Account
		Support					
1	MEPCO	Section 375/392	ws 7, line 5, col. (a)	(\$5,944)	-	(\$5,944)	454
2	Maine Yankee	Section 69	ws 7, line 4, col. (a)	-	-	-	454
3	WF Wyman #4 Joint Owners	Sections 164-167	ws 7, line 3, col. (a)	(207,627)	-	(207,627)	454
4	WF Wyman #4 Joint Owners	Section 386	ws 7, line 2, col. (a)	(95,646)	(126,271)	(221,917)	454
5	FPL			-	(208,780)	(208,780)	454
6	PSNH	Section 214 (from Kimball Rd substation)		-	-	-	454
7							
8		Total Support Revenues	ws 7, line 11, col. (a)	(\$309,217)	(\$335,051)	(\$644,268)	
9							
10		Wheeling					
11	Jurisdictional Sales			(136,594,336)	\$ -	(136,594,336)	FFI p330 lines 11 thru 15
12	RNS, TOUT, Sch 1			(134,844,567)	-	(134,844,567)	FFI p330 line 8
13	HVDC - Sch 20A-CMP				(4,346,839)	(4,346,839)	FFI p330 lines 2 thru 6
14							
15		Total Wheeling Revenues		(\$271,438,903)	(\$4,346,839)	(\$275,785,742)	FF 1 p330 total col n.
16							
17							
18							
19							
20							
21	RNS			128,835,067	450 Notes for FF1 p.328, line 24		
22	SCH 1			4,289,438			
23	TOUT			1,720,062			
24	TOTAL		line 12, above	134,844,567			

**CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

	Party Paid	facility/Nature of Expenses	RNS Rate Worksheet Reference	PTF	Non-PTF	Total	FERC Account
		Support					
1	Boston Edison	7.1205 % of the cost of service for HQ Ph II, AC	ws 7, line 1, col b	\$ 32,348	-	\$32,348	566
2	NEP	NEP Ph II, AC -O&M		187,089	-	\$187,089	566
3		NEP Ph II, AC -RENTS		115,801	-	\$115,801	567
4		NEP Ph II, AC -INTEREST		160,861	-	\$160,861	431
5		NEP Ph II, AC -TOTAL	ws 7, line 8, col b	463,750	-	\$463,750	
6		NHH- Chester SVC	ws 7, line 7, col b	195,473	-	\$195,473	566
7							
8		Total Support Expenses	ws 7, line 11, col b	\$ 691,571	-	\$691,571	
9							
10		Wheeling					
11							
12	ISO-NE	Charges under the OATT		93,165,066		\$93,165,066	lines 36 below
13	Bangor Hydro	Firm PTP Reservation for Energy Transferred to Herman Sta.		-	324,867	\$324,867	565 FF1 pg 332, line 4
14	ISO-NE	Sch 1 - Part IV of ISO-NE Tariff		2,131,001		\$2,131,001	line 37 below
15	PSNH	Bolt Hill		36,029		\$36,029	565010 F1 pg 332, line 2
16							
17		Total Wheeling Expenses		\$95,332,096	\$324,867	\$95,656,963	FERC Form 1 page 332
18							
19							
20							
21		SUMMARY BY FERC ACCOUNT:					
22		431				\$ 160,861	
23		565				95,656,963	FERC Form 1 page 332
24		566				414,910	
25		567 (566+567 to ws 4, line 13)			530,711	115,801	
26						\$ 96,348,534	
27							
28	RNS					\$ 87,759,799	
29	Sch 1					2,200,932	
30	Sch 2 -CC					1,549,943	
31	Sch 2 -VAR Uplift					299,608	
32	Congestion Uplift					-	
33	Sch 16					702,452	
34	Load Response					579,994	
35	Sch 5-NESCO					72,338	
36	Total Charges ISO OATT					93,165,066	
37	ISO-NE Sch 1					2,131,001	450.1 Notes for FFI p.332.6
38	Total ISO Tariff					\$ 95,296,067	565 FF1 pg 332, line 6.h.

**CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

				CAPITALIZATION		CAPITALIZATION		COST OF		COST OF		EQUITY
				12/31/2011		RATIOS		CAPITAL		CAPITAL		PORTION
	MED-TERM NOTES			418,200,000		24.355%		6.671%				
	POLLUTION CONTROL NOTES			19,500,000		1.136%		5.594%				
	FAME			-		0.000%		0.000%				
	MORTGAGE BONDS			150,000,000		8.736%		4.200%				
	TOTAL LONG-TERM DEBT	page 112.21c		587,700,000		34.227%		5.970%		2.043%		
	PREFERRED STOCK	page 112.3c		2,660,500		0.155%		5.062%		0.008%		0.008%
	COMMON EQUITY	page 112.16c less line 3c		1,126,741,425		65.619%		11.640%		7.638%		7.638%
	TOTAL INVESTMENT RETURN			1,717,101,925		100.00%				9.689%		7.646%

**CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

Source: Fixed Assets			
Vintage	cost	afudc	% of total
1953-1970	-----no afudc data available-----		
1971	16,993,929	210,398	1.24%
1972	1,354,874	0	0.00%
1973	2,530,521	21,837	0.86%
1974	3,929,745	200	0.01%
1975	4,626,387	38,383	0.83%
1976	6,559,880	76,909	1.17%
1977	5,885,933	86,351	1.47%
1978	17,338,606	444,301	2.56%
1979	4,115,534	14,481	0.35%
1980	7,717,864	28,543	0.37%
1981	3,806,576	45,143	1.19%
1982	3,336,346	16,508	0.49%
1983	5,462,226	107,741	1.97%
1984	6,543,576	188,256	2.88%
1985	2,153,012	13,995	0.65%
1986	4,063,381	72,616	1.79%
1987	6,308,982	70,120	1.11%
1988	8,616,426	96,074	1.12%
1989	8,190,862	92,568	1.13%
1990	18,606,637	300,769	1.62%
1991	6,804,433	68,667	1.01%
1992	10,041,560	178,995	1.78%
1993	5,637,279	121,080	2.15%
1994	3,480,922	26,059	0.75%
1995	3,820,449	32,298	0.85%
1996	2,681,701	20,928	0.78%
1997	1,790,063	23,501	1.31%
1998	1,477,852	4,185	0.28%
1999	1,810,857	10,989	0.61%
2000	26,037,439	264,455	1.02%
2001	8,983,040	92,232	1.03%
2002	8,622,712	117,487	1.36%
2003	2,701,882	(16,453)	-0.61%
2004	13,379,541	151,747	1.13%
2005	10,790,340	187,716	1.74%
2006	14,151,218	57,062	0.40%
2007	41,386,528	247,340	0.60%
2008	84,332,796	3,500,923	4.15%
2009	44,549,845	355,246	0.80%
2010	20,636,193	558,551	2.71%
2011	87,885,769	374,354	0.43%
TOTALS	539,143,716	8,302,555	1.54%
Depreciation Exp from w/s 1			2,624,601
AFUDC adj to w/s 2			40,418

**CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

INVESTMENT-FERC A/C 101.1				
(Not included in transmission plant)				
G/L	ACCT	CAPITAL LEASES		RNS Rate w/s or FERC Form I Ref.
			BALANCE	
	101101	Edison Drive	5,215,783	
	101103	NEETCO HQDC	-	
	101104	VETCO HQDC	-	
	101105	NEP HQAC	2,504,818	
	101106	NHH HQDC	1,577,933	
	101107	NEH HQDC	2,524,057	
TOTAL CAPITAL LEASES			\$ 11,822,590	Page 112.26+113.49

**CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

			PTF		Total PTF	Non-PTF	Total Transmission		
			pre 1997	post 1996					
TRANSMISSION LINES			76,907,497	84,371,458	161,278,955	99,568,262	260,847,217		
SUBSTATIONS			32,510,946	162,490,952	195,001,898	123,943,848	318,945,746		
TOTALS			109,418,443	246,862,410	356,280,853	223,512,110	579,792,963	FFI.207.58(g)	
Less SCADA & RTUs directly assigned to Schedule 1			723,954	1,633,335	2,357,289	1,478,840	3,836,129	w/s 16	
Totals for RNS			108,694,490	245,229,075	353,923,565	222,033,270	575,956,834	w/s 17, line 3	
PRE 1997 PTF - from above							\$ 108,694,490	to w/s 5, line 1	
POST 1996 PTF - from above							245,229,075	to Post 96 w/s 5, line 1	
Total PRE 97 AND POST 96 PTF							\$ 353,923,565	Total PTF Investment for RNS	

**CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

PROPERTY DESCRIPTION	PROPERTY CLASSIFICATION	COST	ref	RESERVE	ref	DEPRECIATION	ref
Furniture & Equipment	General	2,700,589		246,358		88,409	
Structure Costs & Map Boards	General	4,468,109		1,702,845		100,676	
UPS	General	284,858		158,675		10,550	
EMS Hardware	General	1,834,871		1,495,973		203,854	
LMS	General	-		-		-	
EBCC	General	-		-		-	
Communication Equipment	General	815,265		541,468		59,677	
PC Equipment	General	-		-		-	
		10,103,692	w/s 17,5b	4,145,319	w/s 17,7b	463,167	w/s 17,6b
EMS Software	Intangible	7,900,188		7,900,188		-	
S/S RTU's & Scada	Transmission	3,836,129	w/s 17,3b	1,188,538	w/s 17,4b	93,566	w/s 17,2b
Total Plant Directly Assigned to Schedule 1		21,840,009		13,234,045		556,734	

**CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

			A	B	C	D			
			FERC FORM 1TOTAL	LESS COST RECOVERED UNDER SCH 1	Adjustments	ADJUSTED TOTAL		WORKSHEET REFERENCE FOR COL. D	
	WAGES & PAYROLL EXPENSES								
1	FERC FORM 1, PG. 354, LINE 21B		4,097,185	(1,812,200)	-	2,284,985	1	WS 5, LINE 4	
	TRANSMISSION DEPRECIATION EXP								
2	FERC FORM 1, PG. 336, LINE 7B		13,766,457	(93,566)	-	13,672,891	2	WS 4, LINE 1	
	TOTAL TRANSMISSION PLANT								
3	FERC FORM 1, PG. 207, LINE 58G		579,792,963	(3,836,129)	-	575,956,834	3	WS 5, LINE 2	
	TRANSMISSION PLANT DEPREC. RES.								
4	FERC FORM 1, PG 219, LINE 25c		181,030,497	(1,188,538)	-	179,841,959	4	WS 3, LINE 5	
	TOTAL GENERAL PLANT								
5	FERC FORM 1, PG 207, LINE 99g		184,449,763	(10,103,692)	-	174,346,071	5	WS 3, LINE 2	
	GENERAL DEPRECIATION EXPENSE								
6	FERC FORM 1, PG. 336, LINE 10f		4,542,572	(463,167)	-	4,079,405	6	WS 4, LINE 2	
	GENERAL DEPRECIATION RESERVE								
7	FERC FORM 1, PG 219, LINE 28c		81,672,162	(4,145,319)	-	77,526,843	7	WS 3, LINE 6	
	TRANSMISSION O&M								
8	FERC FORM 1, PG 321, LINE 112b		112,518,656	-		112,518,656	8	WS 4, LINE 10	
	TRANSMISSION PLANT HELD FOR FUTURE USE								
9	FF I, P 214, LINE 47 - (15+16)		3,396,312	-	-	3,396,312	9	WS 3, LINE 4	

**CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

EHV PTF							
			UG	NO OF	MILES	CKT	
<u>LINE</u>	<u>KV</u>	<u>CONDUCTOR</u>	<u>OH</u>	<u>CKTS</u>	<u>PER CKT</u>	<u>MILES</u>	
Scobie - Buxton (CMP Section) (391)	345	2-850.8 ACSR	OH	1	30.6	30.6	
Buxton - Surowiec (374)	345	2-850.8 ACSR	OH	1	26.6	26.6	
Deerfield - Buxton (CMP Section) (385)	345	2-850.5 ACSR	OH	1	30.6	30.6	
Buxton - Maine Yankee (375)	345	2-850.8 ACSR	OH	1	54.5	56.2	
		2-900 ACSR	OH	1	1.7		
Surowiec - Maine Yankee (377)	345	2-850.8 ACSR	OH	1	25.9	29.8	
		2-900 ACSR	OH	1	3.9		
Maine Yankee - Mason (378)	345	2-850.8 ACSR	OH	1	3.5	3.5	
Buxton - South Gorham (386)	345	2-954 ACSR	OH	1	7.1	7.1	

TOTAL CENTRAL MAINE POWER COMPANY EHV PTF CKT. MILES						184.4	

**CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

Central Maine Power						
Lower Voltage PTF						
LINE	KV	CONDUCTOR	UG OH	NO OF CKTS	MILES PER CKT	CKT MILES
Wyman - Livermore Falls (63)	115	795 ACSR	OH	1	47.20	47.20
Livermore Falls - Gulf Island (200)	115	795 ACSR	OH	1	24.30	24.30
Wyman - Heywood Rd (83)	115	477 ACSR	OH	1	41.03	41.03
Heywood Rd - Winslow (242)	115	477 ACSR	OH	1	1.10	1.10
Heywood Rd - Section 67A Tap (67A)	115	795 ACSR	OH	1	3.79	3.79
Winslow - Maxcys (84)	115	477 ACSR	OH	1	25.70	25.70
Wyman - Detroit (66)	115	795 ACSR	OH	1	33.40	33.40
Detroit - Maxcys (67)	115	795 ACSR	OH	1	40.50	40.50
Detroit - Bucksport (203)	115	795 ACSR	OH	1	34.10	34.10
Bucksport - Orrington (CMP Secs only) (65 & 205)	115	795 ACSR	OH	2	6.63	13.30
Bucksport - Highland (86)	115	477 ACSR	OH	1	5.50	39.30
		1272 Al	OH	1	30.20	
		795 ACSR	OH	1	3.60	
Highland - Newcastle (226)	115	1272 Al	OH	1	19.00	19.00
Mason - Newcastle (204)	115	1272 Al	OH	1	11.10	11.10
Highland - Maxcys (80)	115	266.8 ACSR	OH	1	22.00	22.00
Maxcys - Mason (68)	115	795 ACSR	OH	1	23.20	23.20
Maxcys - Bowman Street (60)	115	795 ACSR	OH	1	12.40	12.40
Bowman St. - Gulf Island (212)	115	795 ACSR	OH	1	22.50	22.50
Mason - Bath 115 (207)	115	266.8 ACSR	OH	1	0.50	15.60
		795 ACSR	OH	1	15.10	
Mason - Surowiec (81)	115	336.4 ACSR	OH	1	28.60	28.60
Gulf Island - Surowiec (64)	115	795 ACSR	OH	1	17.60	17.60
Surowiec - Spring Street (166)	115	795 ACSR	OH	1	24.20	24.20
Gulf Island - Crowleys (201)	115	795 ACSR	OH	1	8.30	8.30
Crowleys - Surowiec (62)	115	795 ACSR	OH	1	9.30	9.30
Yarmouth - Moshers (165)	115	795 ACSR	OH	1	19.90	19.90
Yarmouth - Spring St. (164)	115	795 ACSR	OH	1	23.30	23.30
Moshers - South Gorham (162)	115	1113 ACSR	OH	1	3.40	3.40
Westbrook 115 - South Gorham (169)	115	2-1113 ACSR	OH	1	3.00	3.00
Westbrook 115 - Spring St (232)	115	2-1113 ACSR	OH	1	0.90	0.90
Westbrook 115 - South Gorham (231)	115	2-1113 ACSR	OH	1	3.00	3.00
Westbrook 115 - Spring St (233)	115	2-1113 ACSR	OH	1	0.90	0.90
Maguire Rd - Quaker Hill (140)	115	1113 ACSR	OH	1	10.30	10.30
Three Rivers - Quaker Hill (197)	115	1113 ACSR	OH	1	9.40	9.40
Maguire Rd - Three Rivers (250)	115	795 ACSR	OH	1	19.50	19.50
Louden - Maguire Rd (238)	115	795 ACSR	OH	1	11.40	11.40
Louden - Maguire Rd (163)	115	1113 ACSR	OH	1	11.40	11.40
Pleasant Hill - Cape Steam (160)	115	4/0 Cu	OH	1	1.20	4.20
		795 ACSR	OH	1	3.00	
Bath 115 - Surowiec (69)	115	795 ACSR	OH	1	20.85	20.85
Sewall St. - Fore River (277)	115	2500 MCM AL	UG	1	1.25	1.25
Fore River - Cape Steam (275)	115	2500 MCM AL	UG	1	1.39	1.39
Surowiec - Moshers (167)	115	795 ACSR	OH	1	20.90	20.90
Gulf Island - Norway (61)	115	795 ACSR	OH	1	18.40	18.40
Norway - Kimball Rd. (87)	115	795 ACSR	OH	1	6.60	6.60
Surowiec - Raymond (208)	115	795 ACSR	OH	1	15.70	15.70
Raymond - Kimball Rd. (209)	115	795 ACSR	OH	1	16.50	16.50
Kimball Road - PSNH St #1 (214)	115	795 ACSR	OH	1	14.87	14.87
Moshers - Sewall St. (161)	115	795 ACSR	OH	1	7.60	7.60
Livermore Falls - Riley (89)	115	795 ACSR	OH	1	7.40	7.40
Riley - Rumford IP (229)	115	795 ACSR	OH	1	15.20	15.20
Rumford - Rumford IP (228)	115	795 ACSR	OH	1	1.10	1.10
Rumford - Rumford IP (243)	115	1113 ACSR	OH	1	1.21	1.21
Rumford IP - Woodstock (221)	115	1113 ACSR	OH	1	20.58	20.58
Woodstock - Kimball Rd. (217)	115	1113 ACSR	OH	1	12.43	12.43
Rumford - Woodstock (211)	115	1113 ACSR	OH	1	13.40	13.40
Woodstock - Kimball Rd. (210)	115	795 ACSR	OH	1	20.60	20.60
Maxcys - Augusta East (88)	115	795 ACSR	OH	1	11.00	11.00
Augusta East - Bowman St. (213)	115	795 ACSR	OH	1	17.00	17.00
South Gorham - Loudon (219 & 220)	115	795 ACSS	OH	2	9.25	18.50
Crowley's - Lewiston Lower (202)	115	795 ACSR	OH	1	3.50	3.50
Hotel Road - Lewiston Lower (75)	115	795 ACSR	OH	1	7.90	7.90
Hotel Road - Junction Section 61 (61A)	115	795 ACSR	OH	1	10.60	10.60
South Gorham - W. Buxton (223)	115	1113 ACSR	OH	1	9.10	9.10
W. Buxton - Waterboro (224)	115	1113 ACSR	OH	1	8.10	8.10
Waterboro - Sanford (225)	115	1113 ACSR	OH	1	12.60	12.60
Sanford - Maguire Rd (237)	115	795 ACSR	OH	1	7.20	7.20
TOTAL CENTRAL MAINE POWER COMPANY LOWER VOLTAGE PTF CKT. MILES						959.60
TOTAL CENTRAL MAINE POWER COMPANY CKT. MILES						1144.00

**CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

Through and Out Revenues				
	From Worksheet 10, line 23	1,720,062		
		-		
	Short-Term & Non-Firm T&O	1,720,062	See p.450 notes for p328,line 8	
	PTF BALANCE (see w/s 15)	% OF TOTAL	allocation of	
			T/O Revenues	
PRE 1997 PTF	108,694,490	30.71%	528,253	
POST 96 PTF	245,229,075	69.29%	1,191,809	
TOTAL	353,923,565	100.00%	1,720,062	

**CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

	Description	FERC Account	FFI Balance	Reference	
1	SFAS no. 109, Accounting for Income Taxes		13,475,762		
2	Transmission (excluding SFAS No. 109)		41,410,601	worksheet 3, line 9 col 1	
3	Distribution/Other (excluding SFAS No. 109)		184,682,115		
4	Total Accumulated Deferred Income Taxes:	190	239,568,478	FFI page 234, line18	
5	Transmission		6,379,370	worksheet 4, line 6 col 1	
6	Distribution/Other		14,305,251		
7	Total Real and Personal Property Taxes	408.1	20,684,621	FFI page 263(i), line14	

**CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/11**

				Attachment F			
				Reference			Reference
Line No.	II. INVESTMENT BASE		Section:				
1	Transmission Plant		II (A)(1)(a)	\$ 245,229,075			Worksheet 3, line 1 column 5
2	General Plant		II (A)(1)(b)	4,266,961			Worksheet 3, line 2 column 5
3	Plant Held For Future Use		II (A)(1)(c)	1,446,072			Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)			250,942,108			
5	Accumulated Depreciation		II (A)(1)(d)	(78,469,969)			Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes		II (A)(1)(e)	(37,204,492)			Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt		II (A)(1)(f)	410,492			Worksheet 3, line 11 column 5
8	Other Regulatory Asssets		II (A)(1)(g)	233,190			Worksheet 3, line 14 column 5
9	Net Investment (Line 4+5+6+7+8)			135,911,329			
10							
11	Prepayments		II (A)(1)(h)	72,088			Worksheet 3, line 15 column 5
12	Materials & Supplies		II (A)(1)(i)	1,626,733			Worksheet 3, line 16 column 5
13	Cash Working Capital		II (A)(1)(j)	790,918			Worksheet 3, line 23 column 5
14	MPRP CWIP		II (A)(1)(k)	469,939,977			Worksheet 3, line 24 column 6
15	Total Investment Base (Line 9+11+12+13+14)			\$ 608,341,045			
	II. REVENUE REQUIREMENTS						
16	Investment Return and Income Taxes		II (A)	\$ 98,625,879			Worksheet 2
17	Depreciation Expense		II (B)	5,921,442			Worksheet 4, line 3 column 5
18	Amortization of Loss on Reacquired Debt		II (C)	94,539			Worksheet 4, line 4 column 5
19	Investment Tax Credit		II (D)	(95,029)			Worksheet 4, line 5 column 5
20	Municipal Taxes		II (E)	2,716,189			Worksheet 4, line 8 column 5
21	Payroll Taxes		II (F)	-			Worksheet 4, line 9 column 5
22	Operation & Maintenance Expense		II (G)	5,426,659			Worksheet 4, line 14 column 5
23	Administrative & General Expense		II (H)	900,687			Worksheet 4, line 18 column 5
24	Transmission Related Integrated Facilities Charge		II (I)	-			
25	Transmission Support Revenue		II (J)	-			
26	Transmission Support Expense		II (K)	-			
27	Transmission Related Expense from Generators		II (L)	-			
28	Taxes and Fees		II (M)	-			
29	Revenues for TOUT Transmission Service		II (N)	(1,191,809)			W/S 13
30	Transmission Rents Received from Electric Property		II (O)	-			
31	Total Revenue Requirements (Line 16 thru 30)			\$ 112,398,557			
	Forecasted Transmission Revenue Requirements - 2011			54,449,814			Worksheet 16, line 3
	Total - 2011 Actual + 2012 Forecasted			\$ 166,848,371			

**CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/11**

[illegible]

**CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/11**

	Investment Base Calculation for Incremental Return and Associated Income Taxes for Post-2003 PTF, MPRP PTF and MPRP CWIP						
		TOTAL MPRP		MPRP CWIP		MPRP PTF	Post 2003 RSP PTF
1	MRPP CWIP	\$ 469,939,977		\$ 469,939,977		\$ -	\$ -
2	MPRP PTF Investment	54,775,636		-		54,775,636	73,955,838
3	Depreciation Reserve	(2,076,003)		-		(2,076,003)	(7,921,332)
4	Accumulated Deferred Income Taxes	(14,763,926)		-		(14,763,926)	(12,948,119)
5	INVESTMENT BASE	\$ 507,875,684		\$ 469,939,977		\$ 37,935,708	\$ 53,086,387
		w/s 2 line 40					w/s 2 line 40
6	Cost of Capital Rate - 11.64% ROE (w/s 2 line 33)			14.95909%			
7	Cost of Capital Rate - 1.25% bp ROE adder for MPRP (w/s 2 line 8)			1.38524%			
8	MPRP Cost of Capital Rate (MCOC)(6+7)			16.34433%			
9	MPRP CWIP - Base (5 x 6)			\$ 70,298,744			
10	MPRP CWIP - Incremental (5 x 7)			6,509,797			
11	Investment Return and Income Taxes - MPRP CWIP (9+10)			\$ 76,808,541			
12	Investment Return and Income Taxes - Total			\$ 98,625,879	w/s 1, line 16		
13	Less Inv Return&Taxes- MPRP CWIP (11)			76,808,541			
14	Investment Return and Income Taxes - Post96 PTF			\$ 21,817,338			
				w/s 16, line 10			

**CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/11**

			(2)		(4)					RNS Rate			
			Wage/Plant		(3) = (1)*(2)					Worksheet or			
Line		(1)	Allocation		Transmission	Allocation		(5) = (3)*(4)		FERC Form 1			
No.		Total	Factors		Allocated	Factor (b)		Allocated		Reference for col (1) or (5)			
	<u>Transmission Plant</u>												
1	Transmission Plant	-			-			245,229,075	(d)	w/s 5, line 1			
2	General Plant	174,346,071	5.7481%	(a)	10,021,586	42.5777%		4,266,961		w/s 12, line 6			
3	Total (line 1+2)				10,021,586			249,496,036					
4	<u>Transmission Plant Held for Future Use</u>	3,396,312			3,396,312	42.5777%		1,446,072		w/s 12, line 9			
	<u>Transmission Accumulated Depreciation</u>												
5	Transmission Accum. Depreciation	(179,841,959)			(179,841,959)	42.5777%		(76,572,570)		w/s 12, line 4			
6	General Plant Accum. Depreciation	(77,526,843)	5.7481%	(a)	(4,456,320)	42.5777%		(1,897,399)		w/s 12, line 7			
7	Total (line 6+7)	(257,368,802)			(184,298,279)			(78,469,969)					
	<u>Transmission Accumulated Deferred Taxes</u>												
8	Accumulated Deferred Taxes (281-283)	(128,790,829)			(128,790,829)	42.5777%		(54,836,173)		See p. 450 notes for pages 274 & 276 Pre97 w/s 21, line 2			
9	Accumulated Deferred Taxes (190)	41,410,601			41,410,601	42.5777%		17,631,681					
10	Total (line 8+9)	(87,380,228)			(87,380,228)			(37,204,492)					
11	<u>Unamortized loss on Reacquired Debt</u>	3,088,334	31.2175%	(c)	964,101	42.5777%		410,492		Page 111.81c			
	<u>Other Regulatory Assets</u>												
12	FAS 106	9,528,029	5.7481%	(a)	547,681					Page 232.1, lines 4f+8f			
13	FAS 109	-								DITs functionalized in FF 1 excluding FAS109 DITs, therefore the 109 reg asset is properly excluded.			
14	Total (line 12+13)	9,528,029			547,681	42.5777%		233,190					
15	<u>Transmission Prepayments</u>	2,945,473	5.7481%	(a)	169,309	42.5777%		72,088		FF I 111.57c			
16	<u>Transmission Materials and Supplies</u>	3,820,623			3,820,623	42.5777%		1,626,733		See note for page 227.11c on Page 450			
17	<u>Cash Working Capital</u>												
18	Operation & Maintenance Expense							5,426,659		Worksheet 1, Line 22			
19	Administrative & General Expense							900,687		Worksheet 1, Line 23			
20	Net Transmission Support Expense							-					
21	Subtotal (line 18+19+20)							6,327,346					
22								0.125		x 45 / 360			
23	Total (line 21 * line 22)							790,918					
24	<u>MPRP CWIP</u>	469,939,977						469,939,977		p.450 notes for page 216.7b			
	(a) Worksheet 5 of 8, line 11												
	(b) Worksheet 5 of 8, line 3												
	(c) Worksheet 5 of 8, line 16												
	(d) EHV/LV PTF Facilities												

**CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/11**

			(2)		(4)				
Line		(1)	Wage/Plant	(3) = (1)*(2)	PTF	(5) = (3)*(4)	Worksheet or		
No.		Total	Allocation	Transmission	Allocation	PTF	FERC Form 1		
			Factors	Allocated	Factor (b)	Allocated	Reference for col (1)		
	<u>Depreciation Expense</u>								
1	Transmission Depreciation	13,672,891		13,672,891	42.5777%	5,821,602	w/s 12, line 2		
2	General Depreciation	4,079,405	5.7481%	234,488	42.5777%	99,840	w/s 12, line 6		
3	Total (line 1+2)			13,907,379		5,921,442			
4	<u>Amortization of Loss on Reacquired Debt</u>	711,263	31.2175%	222,039	42.5777%	94,539	Page 117.64c		
5	<u>Amortization of Investment Tax Credits</u>	(714,950)	31.2175%	(223,190)	42.5777%	(95,029)	Page 266.8f		
	<u>Property Taxes *</u>								
6	Transmission Property Taxes	6,379,370		6,379,370	42.5777%	2,716,189	PRE-97 w/s 21, line 5		
7	General Property Taxes	-	5.7481%		42.5777%	-			
8	Total (line 1+2)	6,379,370		6,379,370		2,716,189			
9	Payroll Taxes	-	-	(d)	-	-			
	<u>Transmission Operation and Maintenance</u>								
10	Operation and Maintenance	112,518,656					w/s 12, line 8		
11	Transmission of Electricity by Others - #565	95,656,963					Page 321.96b/332/pre97 ws 11, line 17		
12	Load Dispatching - #561	3,585,675					Page 321.84 thru 88b		
13	**Station Expenses & Rents - #562 / #567	530,711					PRE-97 ws 11, line 25		
14	O&M - line 10 less lines 11, 12, & 13	12,745,307		12,745,307	42.5777%	5,426,659			
	<u>Transmission Administrative and General</u>								
15	A & G subject to Wage & Salaries Allocation Factor	39,364,926	5.7481%	2,262,735			w/s 7, line 28		
16	A & G subject to Plant Allocation Factor	290,630	31.2175%	90,727			w/s 7, line 31		
17	A & G directly assigned to transmission	(238,067)	100.00%	(238,067)			w/s 7, line 36		
18	A&G (line 14+15)	39,417,489		2,115,395	42.5777%	900,687			
	* Property Taxes not functionalized per FERC Form 1; therefore, need to use Plant Allocation Factor								
	(a) Worksheet 5 of 8, line 11								
	(b) Worksheet 5 of 8, line 3								
	(c) Worksheet 5 of 8, line 16								
	(d) Payroll taxes - FERC Form 1, page 263 lines 3,5&9 col i&l are recorded in acc't 184								
	and then cleared and properly functionalized to the appropriate accounts.								
	** Subtract Accounts #566 & #567 from O&M Expense to the extent that they include PTF Support Payments.								

**CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/11**

						RNS Rate		
						Worksheet or		
Line						FERC Form 1		
No.						Reference		
		<u>PTF Transmission Plant Allocation Factor</u>						
				Post 1996				
1	PTF Transmission Investment			245,229,075		w/s 10		
2	Total Transmission Investment			575,956,834		w/s 12, line 3 & w/s 10		
3	Percent Allocation (line 1/2)			42.5777%				
		<u>Transmission Wages and Salaries Allocation Factor</u>						
4	Direct Transmission Wages and Salaries			2,284,985		w/s 12, line 1		
5	Affiliated Company Transmission Wages and Salaries			-				
6	Total Transmission Wages and Salaries (line 4+ 5)			2,284,985				
7	Total Wages and Salaries			44,543,516		Page 354.28b + line 5		
8	Administrative and General Wages and Salaries			4,791,627		Page 354.27b		
9	Affiliated Company Wages and Salaries less A&G			-				
10	Total Wages and Salaries net of A&G (line 7 - 8 + 9)			39,751,889				
11	Percent Allocation (line 6/10)			5.7481%				
		<u>Plant Allocation Factor</u>						
12	Total Transmission Investment (excluding capital leases)			575,956,834		ws 5 line 2		
13	Transmission Related General Plant			10,021,586		ws 3 line 2		
14	Total Transmission Related Plant			585,978,420				
15	Total Electric Plant in Service (excluding capital leases)			1,877,082,238		Page 207.104g		
16	Percent Allocation (line 14/15)			31.2175%				

**CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/11**

Affiliated Company Wages and Salaries									
Line									
"Affiliated" Transmission Wages and Salaries				Transmission Wages by 3 digit FERC					
#560 - 573									
				560	270,006				
1	560		-	561-561.4	1,812,200	w/s 12 line 1b			
2	562		-	561.5-561.8	73,252				
3	564		-	562	475,811				
4	566		-	563	9,573				
5	568		-	564	602				
6	569		-	566	568,259				
7	570		-	567	-				
8	571		-	568	151,334				
9	572		-	569	40,471				
10	573		-	570	450,430				
11 = 1 thru 10	Total Transmission		-	571	217,851				
				572	27,396				
				573	-				
					4,097,185	w/s 12, line 1a			
12 = Total "Affiliated" Wages and Salaries			-						
Less "Affiliated" Administrative and General Salaries									
#920 - 935									
13	920		-						
14	921		-						
15	923		-						
16	925		-						
17	926		-						
18	928		-						
19	930		-						
20	935		-						
21 = 13 thru 20			-						
22 = 12 less 21	Total "Affiliated" less A&G		-						
				To Worksheet 5					

**CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/11**

	Acc't	Description	Amount	
1	920	Administrative and General Salaries	6,838,260	
2	921	Office Supplies and Expenses	2,612,247	
3	922	Less Administrative Expenses Transferred	(490,590)	
4	923	Outside Services	22,771,469	
5	924	Property Insurance	290,630	
6	925	Injuries and Damages	2,312,523	
7	926	Employee Pensions and Benefits	(7,064,577)	
8	928	Regulatory Commissions Expense	4,728,904	
9	930.1	General Advertising	1,628,798	
10	930.2	Miscellaneous General Expense	1,582,968	
11	931	Rents	921,706	
12	935	Maintenance of General Plant	1,785,722	
13		Total Admin & Gen'l Exp.	37,918,060	Page 323.197b
14		FERC assessments - Transmission (directly assigned)	676,625	FF1 page 350.d
15		FERC assessments - subject to plant allocation factor	-	FF1 page 350.d
16		TOTAL FERC ASSESSMENTS (14+15)	676,625	FF1 page 350.d
17		State assessments - Transmission (directly assigned)	54,510	FF1 page 350.d
18		Total State Assessments	4,052,279	FF1 page 350.d
19	928	Total Regulatory Commissions Expense: (16+18) & from line 8	4,728,904	FF1 page 350.d, line 46
20		General Advertising - Transmission related	-	
21		Non-Transmission related General Advertising Exp.	1,628,798	
22	930.1	Total General Advertising Exp. (line 9)	1,628,798	
		Summary of Attachment F treatment of A&G		
23		Total A&G (line 13)	37,918,060	
24	924	less Property Insurance (line 5)	290,630	
	926	less pension credit directly assigned to T&D	(8,095,198)	
25	928	less Regulatory Commissions Exp. (line 19)	4,728,904	
26	930.1	less Non-Trans. General Advertising Exp. (line 9)	1,628,798	
27	920-935	less EPRI Expenses	-	
28		A&G subject to Wages and Salaries Allocation Factor:	39,364,926	to worksheet 4, line 15, column 1
29		Property Insurance (line 5)	290,630	
30		Regulatory Commissions Exp. - FERC assessments (line 15)	-	
31		Total A&G subject to Plant Allocation Factor	290,630	to worksheet 4, line 16, column 1
		Items Directly Assigned to Transmission		
33	926010	MRFV - transmission only portion of pension credit	(969,202)	MPUC Docket Nos. 2007-215/2008-111
34		State assessments - Transmission (directly assigned) (Line 19 above)	54,510	
35		FERC Reg Comm Exp - Trans (directly assigned) (Line 14 above)	676,625	
36		total to w/s 4, line 17	(238,067)	w/s 4, line 17

**CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/11**

				CAPITALIZATION		CAPITALIZATION		COST OF		COST OF		EQUITY
				12/31/2011		RATIOS		CAPITAL		CAPITAL		PORTION
	MED-TERM NOTES			418,200,000		24.355%		6.671%				
	POLLUTION CONTROL NOTES			19,500,000		1.136%		5.594%				
	FAME			0		0.000%		0.000%				
	MORTGAGE BONDS			150,000,000		8.736%		4.200%				
	TOTAL LONG-TERM DEBT	page 112.21c		587,700,000		34.227%		5.970%		2.043%		
	PREFERRED STOCK	page 112.3c		2,660,500		0.155%		5.062%		0.008%		0.008%
	COMMON EQUITY	page 112.16c less line 3c		1,126,741,425		65.619%		11.640%		7.638%		7.638%
	TOTAL INVESTMENT RETURN			1,717,101,925		100.00%				9.689%		7.646%

**CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/11**

Source: Fixed Assets			
Vintage	cost	afudc	% of total
1953-1970	-----no afudc data available-----		
1971	16,993,929	210,398	1.24%
1972	1,354,874	0	0.00%
1973	2,530,521	21,837	0.86%
1974	3,929,745	200	0.01%
1975	4,626,387	38,383	0.83%
1976	6,559,880	76,909	1.17%
1977	5,885,933	86,351	1.47%
1978	17,338,606	444,301	2.56%
1979	4,115,534	14,481	0.35%
1980	7,717,864	28,543	0.37%
1981	3,806,576	45,143	1.19%
1982	3,336,346	16,508	0.49%
1983	5,462,226	107,741	1.97%
1984	6,543,576	188,256	2.88%
1985	2,153,012	13,995	0.65%
1986	4,063,381	72,616	1.79%
1987	6,308,982	70,120	1.11%
1988	8,616,426	96,074	1.12%
1989	8,190,862	92,568	1.13%
1990	18,606,637	300,769	1.62%
1991	6,804,433	68,667	1.01%
1992	10,041,560	178,995	1.78%
1993	5,637,279	121,080	2.15%
1994	3,480,922	26,059	0.75%
1995	3,820,449	32,298	0.85%
1996	2,681,701	20,928	0.78%
1997	1,790,063	23,501	1.31%
1998	1,477,852	4,185	0.28%
1999	1,810,857	10,989	0.61%
2000	26,037,439	264,455	1.02%
2001	8,983,040	92,232	1.03%
2002	8,622,712	117,487	1.36%
2003	2,701,882	(16,453)	-0.61%
2004	13,379,541	151,747	1.13%
2005	10,790,340	187,716	1.74%
2006	14,151,218	57,062	0.40%
2007	41,386,528	247,340	0.60%
2008	84,332,796	3,500,923	4.15%
2009	44,549,845	355,246	0.80%
2010	20,636,193	558,551	2.71%
2011	87,885,769	374,354	0.43%
TOTALS	539,143,716	8,302,555	1.54%
Depreciation Exp from w/s 1			5,921,442
AFUDC adj to w/s 2			91,187

**CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/11**

			PTF		Total PTF	Non-PTF	Total Transmission		
			pre 1997	post 1996					
TRANSMISSION LINES			76,907,497	84,371,458	161,278,955	99,568,262	260,847,217		
SUBSTATIONS			32,510,946	162,490,952	195,001,898	123,943,848	318,945,746		
TOTALS			109,418,443	246,862,410	356,280,853	223,512,110	579,792,963	FFI.207.58(g)	
Balance per FERC Form 1; p. 207, line 53g			109,418,443	246,862,410	356,280,853	223,512,110	579,792,963		
Less SCADA & RTUs directly assigned to Schedule 1			723,954	1,633,335	2,357,289	1,478,840	3,836,129	w/s 11	
Totals for RNS			108,694,490	245,229,075	353,923,565	222,033,270	575,956,834		
PRE 1997 PTF - from above							\$ 108,694,490	to Pre97 w/s 5, line 1	
POST 1996 PTF - from above							245,229,075	to w/s 5, line 1	
Total PRE 97 AND POST 96 PTF							<u>\$ 353,923,565</u>	Total PTF Investment for RNS	

**CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/11**

PROPERTY DESCRIPTION	PROPERTY CLASSIFICATION	COST	ref	RESERVE	ref	DEPRECIATION	ref
Furniture & Equipment	General	2,700,589		246,358		88,409	
Structure Costs & Map Boards	General	4,468,109		1,702,845		100,676	
UPS	General	284,858		158,675		10,550	
EMS Hardware	General	1,834,871		1,495,973		203,854	
LMS	General	-		-		-	
EBCC	General	-		-		-	
Communication Equipment	General	815,265		541,468		59,677	
PC Equipment	General	-		-		-	
		10,103,692	w/s 12,5b	4,145,319	w/s 12,7b	463,167	w/s 12,6b
EMS Software	Intangible	7,900,188		7,900,188		-	
S/S RTU's & Scada	Transmission	3,836,129	w/s 12,3b	1,188,538	w/s 12,4b	93,566	w/s 12,2b
Total Plant Directly Assigned to Schedule 1		21,840,009		13,234,045		556,734	

**CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/11**

		A	B	C	D			
		FERC FORM 1TOTAL	LESS COST RECOVERED UNDER SCH 1	Adjustments	ADJUSTED TOTAL		WORKSHEET REFERENCE FOR COL. D	
	WAGES & PAYROLL EXPENSES							
1	FERC FORM 1, PG. 354, LINE 21b	4,097,185	(1,812,200)	-	2,284,985	1	WS 5, LINE 4	
	TRANSMISSION DEPRECIATION EXP							
2	FERC FORM 1, PG. 336, LINE 7f	13,766,457	(93,566)	-	13,672,891	2	WS 4, LINE 1	
	TOTAL TRANSMISSION PLANT							
3	FERC FORM 1, PG. 207, LINE 58g	579,792,963	(3,836,129)	-	575,956,834	3	WS 5, LINE 2	
	TRANSMISSION PLANT DEPREC. RES.							
4	FERC FORM 1, PG 219, LINE 25c	181,030,497	(1,188,538)	-	179,841,959	4	WS 3, LINE 5	
	TOTAL GENERAL PLANT							
5	FERC FORM 1, PG 207, LINE 99g	184,449,763	(10,103,692)	-	174,346,071	5	WS 3, LINE 2	
	GENERAL DEPRECIATION EXPENSE							
6	FERC FORM 1, PG. 336, LINE 10f	4,542,572	(463,167)	-	4,079,405	6	WS 4, LINE 2	
	GENERAL DEPRECIATION RESERVE							
7	FERC FORM 1, PG 219, LINE 28c	81,672,162	(4,145,319)	-	77,526,843	7	WS 3, LINE 6	
	TRANSMISSION O&M							
8	FERC FORM 1, PG 321, LINE 112	112,518,656	-		112,518,656	8	WS 4, LINE 10	
	TRANSMISSION PLANT HELD FOR FUTURE USE							
9	FF I, P 214, LINE 47 - (15+16)	3,396,312	-	-	3,396,312	9	WS 3, LINE 4	

**CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/11**

Through and Out Revenues					
From Pre97 Worksheet 10, line 30		1,720,062			
		-			
Short-Term & Non-Firm T&O		1,720,062	See p.450 notes for p328,line 8		
	PTF BALANCE (see w/s 15)	% OF TOTAL	allocation of T/O Revenues		
PRE 1997 PTF	108,694,490	30.71%	528,253		
POST 96 PTF	245,229,075	69.29%	1,191,809		
TOTAL	353,923,565	100.00%	1,720,062		

	Investment		2011 Activity				Investment	
	as of 12/31/10	Additions	Retires	Transfers	Adjustments	as of 12/31/11		
115KV Lines - Excluding Land								
60	\$ 946,521	\$ 0	\$ (433)	\$ -	\$ -	\$ 946,088		
061A	881,448	7,391	-	-	-	888,839		
61	2,566,339	30,610	-	-	-	2,597,549		
62	493,599	6,917	(21,463)	-	-	479,155		
63	1,920,233	65,222	(3,984)	-	-	1,981,471		
64	628,031	885,832	(54,668)	-	-	1,459,196		
65	291,200	-	(1,417)	-	-	289,784		
66	1,046,679	891,868	(68,210)	-	-	1,870,338		
67	5,073,904	1,956,925	(477,810)	(99,420)	-	6,453,598		
067A	541,717	-	-	(28,794)	-	512,923		
68	4,315,974	-	(7,882)	(47,795)	-	4,260,297		
69	2,998,299	23,833	(22,095)	-	-	3,000,036		
75	1,108,877	-	-	-	-	1,108,877		
80	2,022,420	79,550	(87,189)	(2,276)	-	2,012,505		
81	988,751	89,053	(17,047)	-	-	1,060,757		
83	1,445,893	965,071	(1,757)	28,794	-	2,438,001		
84	1,536,853	15,676	-	-	-	1,552,529		
86	4,153,973	704	(5,978)	(10,431)	-	4,138,268		
87	298,935	45,879	-	-	-	345,814		
88	1,204,897	8,668,357	(219,033)	270,471	-	9,924,692		
89	586,791	121,803	(7,377)	-	-	701,217		
140	2,147,014	-	-	276,210	-	2,423,224		
160	597,609	-	-	-	-	597,609		
161	1,191,547	10,366	(394)	-	-	1,201,520		
162	659,081	3,013	(1,958)	-	-	660,137		
163	7,066,782	-	-	633,856	-	7,700,638		
164	2,355,390	350,367	(13,674)	(81,468)	-	2,610,615		
165	853,300	421,713	(9,111)	-	-	1,265,901		
166	1,303,245	23,328	(281)	-	-	1,326,293		
167	1,130,669	2	(403)	-	-	1,130,268		
169	501,035	-	-	-	-	501,035		
197	5,316,063	-	-	-	-	5,316,063		
200	967,305	10,787	(910)	-	-	977,182		
201	1,505,421	-	(1,006)	-	-	1,504,415		
202	315,157	-	-	-	-	315,157		
203	1,032,597	173,350	(11,697)	-	-	1,194,250		
204	957,721	-	(122)	22,413	-	980,012		
205	386,305	-	(768)	-	-	385,538		
207	1,798,053	12,392	(5,150)	-	-	1,805,295		
208	667,742	10,177	-	-	-	677,919		
209	868,872	-	(14,920)	-	-	853,952		
210	1,828,178	-	(8,014)	(228,177)	-	1,591,986		
211	8,521,749	37,357	-	325,310	-	8,884,415		
212	1,737,270	5,868	(6,740)	-	-	1,736,398		
213	2,355,649	33,501	(3,271)	(125,505)	-	2,260,374		
214	1,670,056	-	(767)	-	-	1,669,289		
217	3,553,887	-	(5,088)	(52,994)	-	3,495,806		
219	8,533,147	-	-	(30,358)	-	8,502,789		
220	4,622,971	-	-	(226,366)	-	4,396,605		
221	437,177	-	-	-	-	437,177		
223	1,842,786	-	(198,145)	-	-	1,644,641		
224	1,796,606	-	-	-	-	1,796,606		
225	2,133,106	-	-	-	-	2,133,106		
226	1,891,111	275	(563)	(7,457)	-	1,883,366		
228	39,450	12,327	(243)	-	-	51,534		
229	1,211,408	111,315						

**CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/11**

220	25,337	-	-	-	-	25,337	
223	12,878	-	-	-	-	12,878	
224	13,266	-	-	-	-	13,266	
225	55,025	-	-	-	-	55,025	
226	100,393	-	-	-	-	100,393	
228	-	-	-	-	-	-	
229	73,887	-	-	-	-	73,887	
234	7,680	-	-	-	-	7,680	
250	43,747	-	-	-	-	43,747	
275 URD	146,439	-	-	-	-	146,439	
	\$ 5,038,525	\$ 36,687	\$ -	\$ -	\$ -	\$ 5,075,212	
	Investment	2011 Activity				Investment	
	as of 12/31/10	Additions	Retires	Transfers	Adjustments	as of 12/31/10	
345 kV Lines(Including Land)							
374	3,195,722	-	-	-	-	3,195,722	
374 (Temp) Reassign to Substations	-	-	-	-	-	-	
375	4,998,088	149,813	(10,604)	-	-	5,137,297	
377	4,218,878	-	-	-	-	4,218,878	
378	866,515	(10,186)	-	-	-	856,329	
385	3,368,470	242,584	-	-	-	3,611,054	
386	3,832,122	0	(30,752)	-	-	3,801,370	
391	3,015,820	242	-	-	-	3,016,062	
	23,455,615	382,452	(41,356)	-	-	23,796,712	
Total PTF Lines	\$ 146,717,096	\$ 15,525,620	\$ (1,365,847)	\$ 402,086	\$ -	\$ 161,278,954	
	Investment	2011 Activity				Investment	
	as of 12/31/10	Additions	Retires	Transfers	Adjustments	as of 12/31/10	
115 kV Substations							
Augusta East	2,080,872	-	-	-	(5,136)	2,075,736	
WF Wyman	950,221	408,932	(57,191)	-	46,386	1,348,349	
Highland	928,101	7,469	-	-	(0)	935,570	
Mason	3,532,750	2,679,271	-	-	(77,988)	6,134,033	
Marcy's	4,770,785	15,871	-	-	(1,327)	4,785,329	
Topsham	-	-	-	-	-	-	
Bath	1,691,656	14,865	-	-	5,521	1,712,042	
Puddledock	156,334	-	-	-	1,550	157,884	
Bowman St	694,847	1,808,321	-	-	47,960	2,551,128	
Meadow Road	3,405	-	-	-	(3,405)	-	
Newcastle	2,041,230	3,346	-	-	0	2,044,576	
Crowley's	1,948,875	513	-	-	(1,121)	1,948,267	
Gulf Island	2,785,424	8,106	-	-	0	2,793,530	
Hotel Rd	1,301,140	444	(3,402)	-	2,587	1,300,768	
Challenger Drive	155,112	-	-	-	-	155,112	
Kimball Rd	4,810,370	973	-	-	(28)	4,811,315	
Lewiston Lower	702,253	2,981	-	-	-	705,234	
Livermore Falls	1,807,950	6,526	-	-	-	1,814,476	
Lovell	-	-	-	-	-	-	
Norway	23,719	-	-	-	0	23,719	
Surowiec	2,705,287	7,111,324	(768,032)	-	1,506	9,050,085	
Norway Switch	45,083	-	-	-	-	45,083	
Raymond	1,459,130	9	-	-	(366)	1,458,774	
Rumford	561,957	4,817,514	-	-	31,475	5,410,946	
Riley	1,753,262	-	-	-	21,673	1,774,935	
Woodstock	5,316,948	16	-	-	(167,011)	5,149,953	
Rumford IP	6,519,687	4,000	-	-	(643)	6,523,044	
Cape	237,422	-	-	-	(237,422)	-	
Elm Street	75,831	-	-	-	34,103	109,934	
Louden	4,778,614	89,573	-	-	11,912	4,880,099	
Moshers	2,188,287	558,648	(45,615)	-	32,748	2,732,068	
Mussey	405,192	-	-	-	-	405,192	
West Kennebunk	327,668	-	-	-	-	327,668	
Pleasant Hill	969,667	-	(8,543)	-	(33,872)	927,252	
Prides Corner	-	-	-	-	-	-	
Maguire Rd	12,433,615	-	-	-	0	12,433,615	
Quaker Hill	1,176,851	1	-	-	(307)	1,176,546	
Cape	574,641	-	-	-	0	574,641	
Fore River	4,379,712	-	-	-	0	4,379,712	
West Buxton	340,456	-	-	-	(1)	340,455	
Sewall St	558,154	-	-	-	(1)	558,153	
Spring St	1,969,939	-	-	-	0	1,969,939	
Three Rivers	56,647	-	-	-	-	56,647	
Biddeford Ind. Park	103,841	-	-	-	(103,841)	-	
Sanford	1,809,903	2	-	-	103,305	1,913,209	
South Gorham	4,864,838	8,326,331	-	-	(9,068)	13,182,101	
Red Brook	332,879	-	-	-	77	332,956	
Westbrook	1,755,317	-	-	-	0	1,755,317	
Lincolville	304,453	91,994	-	-	(821)	395,625	
Bucksport	2,363,612	286,004	(35,770)	-	22,288	2,636,135	
Detroit	2,794,491	-	-	-	3,747	2,798,238	
Sappi (Hinckley)	-	-	-	-	-	-	
Lakewood	166,546	-	-	-	(166,546)	-	
Searsport	2,247	-	-	-	(2,247)	-	
Sturtevant	142,527	-	-	-	-	142,527	
Winslow	1,763,368	-	-	-	(29,671)	1,733,697	
Heywood Road	6,820,403	9,708	-	-	0	6,830,111	
Wyman	1,572,898	(0)	(3,038)	-	13,398	1,583,258	
Belfast	3,965	-	-	-	(3,965)	-	
	104,018,379	26,252,744	(921,592)	-	(464,549)	128,884,983	
	Investment	2011 Activity				Investment	
	as of 12/31/10	Additions	Retires	Transfers	Adjustments	as of 12/31/10	
345kV Substations							
Coopers Mills Road 345 KV	\$ -	\$ 1,854,613	\$ -	\$ -	-	\$ 1,854,613	
Mason	1,273,415	-	-	-	-	1,273,415	
Marcy's	4,778,857	-	-	-	-	4,778,857	
Maine Yankee	4,189,838	22,800	-	-	-	4,212,638	
Larrabee Road 345KV	-	1,528,069	-	-	-	1,528,069	
Surowiec	4,558,682	9,322	(7,307)	-	-	4,560,697	
Buxton	17,017,735	84,206	(259,770)	-	351	16,842,522	
South Gorham	27,153,762	64,413	-	-	72,711	27,290,886	
Albion Road S/S 345 KV	-	3,775,218	-	-	-	3,775,218	
	\$ 58,972,289	\$ 3,499,011	\$ (267,077)	\$ -	\$ 351	\$ 66,116,915	
Total Substations	\$ 162,990,668	\$ 29,751,755	\$ (1,188,669)	\$ -	\$ (464,198)	\$ 195,001,898	
Total PTF	\$ 309,707,763	\$ 45,277,375	\$ (2,554,516)	\$ 402,086	\$ (464,198)	\$ 356,280,852	
PTF portion of SCADA & RTU Investment Directly Assigned to Schedule 1 (see w/s 15)						(2,357,289)	
Total PTF for Attachment F						\$ 353,923,564	

**CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/11**

Shading denotes an input						
	FORECASTED TRANSMISSION REVENUE REQUIREMENTS (FTRR)	Forecast Period	Attachment F Reference		Amount	Reference
			Section:			
Line No.						
1	Forecasted Rev Req'ts for FTPA				\$ 56,325,532	line 6 below
2	Forecasted Rev Req'ts for FCWIP				(1,875,718)	line 9 below
3	Forecasted Transmission Revenue Requirements (Lines 1 + 2)				\$ 54,449,814	
4	Forecasted Transmission Plant Additions (FTPA)	2011	Appendix C iv		\$ 375,529,433	w/s 17 line 10
5	Carrying Charge Factor (CCF)		Appendix C vi		15.00%	line 20 below
6	Forecasted Rev Req'ts for FTPA (Lines 1*2)				\$ 56,325,532	
7	Forecasted MPRP CWIP (FCWIP)		Appendix C v		\$ (11,476,259)	Annual Report of Construction Costs
8	MPRP Cost of Capital Rate (MCOC)		Appendix C vii		16.34%	line 23 below
9	Forecasted Rev Req'ts for FCWIP (Lines 4*5)				\$ (1,875,718)	
	DERIVATION OF CARRYING CHARGE FACTOR (CCF)					
10	Investment Return and Income Taxes		(A)		\$ 21,817,338	Worksheet 2a, line 14
11	Depreciation Expense		(B)		5,921,442	Worksheet 1, line 17
12	Amortization of Loss on Reacquired Debt		(C)		94,539	Worksheet 1, line 18
13	Investment Tax Credit		(D)		(95,029)	Worksheet 1, line 19
14	Property Tax Expense		(E)		2,716,189	Worksheet 1, line 20
15	Payroll Tax Expense		(F)		-	Worksheet 1, line 21
16	Operation & Maintenance Expense		(G)		5,426,659	Worksheet 1, line 22
17	Administrative & General Expense		(H)		900,687	Worksheet 1, line 23
18	Total Expenses (Lines 10 thru 17)				36,781,825	
19	PTF Transmission Plant		(A)(1)(a)		\$ 245,229,075	Worksheet 1, line 1
20	Carrying Charge Factor (Lines 18/19)				15.00%	
	DERIVATION OF MPRP COST OF CAPITAL RATE (MCOC)					
21	Cost of Capital Rate - 11.64% ROE				14.95909%	Worksheet 2, line 33
22	Cost of Capital Rate - 1.25% bp ROE adder for MPRP				1.38524%	Worksheet 2, line 8
23	MPRP Cost of Capital Rate (MCOC) (Lines 21 + 22)				16.34433%	

**CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/11**

	Projects	FTP
1	MPRP	328,258,236
2	Somerset County Reinforcement Project	19,707,124
3	NERC-Repl 115KV & 345KV T/L Structures	9,672,512
4	Sturtevant S/S New Capacitor Bank	7,267,236
5	Athens New S/S	4,081,173
6	CMP - Mid Cycle Pole Replacement	1,989,162
7	Leeds S/S-Construct new Substation	1,253,693
8	Louden - Upgrade	1,047,577
9	Other Forecasted PTF additions less than \$1M	2,252,721
10	Total PTF FTP	375,529,433
		w/s 16, line 4

Annual Report of MPRP Construction Costs For FERC Informational Filings



Local Filing - June 29, 2012
Regional Filing - July 31, 2012

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**PART I – SUMMARY OF CONSTRUCTION COSTS
FOR FERC INFORMATIONAL FILINGS**

Summary of MPRP Costs for the June 29th & July 31st FERC Informational Filings

1. The actual amount of CWIP recorded each month for the MPRP project for the most recent calendar year.

Attachment 1 provides the actual amount of CWIP recorded each month for the MPRP project for 2011.

Lewiston Loop represents a collection of projects of the MPRP that were not initially approved by the MPUC on June 10, 2010. CMP is currently seeking a separate CPCN for the Lewiston Loop projects. None of the costs for the Lewiston Loop have been included in CMP's transmission rates. Costs for detailed engineering and land purchases are in a CWIP account and are accruing AFUDC until such time that the Lewiston Loop costs are included in rates.

2. Forecast of the year end MPRP CWIP balance for the current calendar year.

By the end of 2012, CMP estimates the year end MPRP CWIP balance will be \$458,463,718 for PTF facilities. CMP estimates the non-PTF balance to be \$9,901,189.

3. A summary and detail of accounting transfers between MPRP CWIP and Plant in Service.

Attachment 1 provides a summary of the account transfers between CWIP and Plant in Service for MPRP.

4. A statement of the current status of the MPRP settlement projects and estimated in-service dates for the program.

Below is a summary of the actual and estimated in-service costs per year for MPRP by PTF and Non-PTF excluding distribution costs currently estimated at \$9,242,224 and the cost of retirements.

Values in Thousands			
Year	PTF	Non-PTF	
2009	\$ 22,435	\$ -	
2010	\$ 4,674	\$ 709	
2011	\$ 27,667	\$ 3,355	
2012	\$ 328,258	\$ 5,330	
2013	\$ 446,398	\$ 9,589	
2014	\$ 397,113	\$ 9,204	
2015	\$ 109,947	\$ 2,444	
Total	\$ 1,336,492	\$ 30,631	

The total estimated cost for components that are fully permitted, including contingency, is \$1,404,922,000. The current projections include costs incurred during the planning, preliminary engineering and permitting phases of work prior to the start of construction, contracting for the majority of required materials and construction labor, program management requirements to the end of construction and contingency required to cover other areas of potential risk.

Deferred projects excluded from the original MPRP scope of work that are pending further study and approval are estimated to be \$107,200,000 and include:

1. Sections 80, 84 and 244
2. Lewiston Loop reinforcement
3. Raven Farm auto transformer, 115kV yard and line terminations
4. Various rebuilds and expansions

The estimated total cost of the MPRP at this time is \$1,512,122,000 with a portion of contingency used to fund design, construction and environmental controls.

Portions of certain deferred projects will need to be constructed under the classifications of "Remote Ends" or "Line Terminations". The work is currently being included under the Settlement projects budget of \$1,404,922,000. However, as designs are finalized and costs become known, the additional scope may result in an increase to the Settlement project budget and a decrease to the Deferred project budget.

5. Project cost estimates in a format similar to ISO-NE informational filings.

Attachment 2 provides cost estimate updates for projects approved by the MPUC (Settlement), projects that are pending additional planning, preliminary engineering and permitting (Deferred) and cost estimates for the Program as a whole (Combined).

* * * * *

ATTACHMENT 1 – MONTHLY CWIP AND PLANT IN-SERVICE BALANCES

**Central Maine Power Company
FERC Informational Filing Attachment 1
MPRP Monthly CWIP and In Service Balances**

	Total As of 12/31/2010	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
CWIP Balance	182,962,461.94	191,851,937.77	202,814,858.67	223,595,363.90	246,971,456.38	265,392,240.65	290,939,207.12	317,764,658.40	347,684,209.61	385,830,367.04	407,185,858.24	441,423,304.03	475,236,151.67
In Service	27,818,872.72	28,004,878.05	28,154,163.14	28,294,044.05	29,029,095.54	29,186,058.37	29,720,048.46	29,193,239.12	29,247,967.97	34,064,205.56	55,567,764.65	58,466,575.99	58,839,630.00

ATTACHMENT 2 – PROJECT COST ESTIMATE UPDATE SHEETS

**FIGURE 1 – MPRP COMBINED PROJECTS
(INCLUDES ALL PROJECTS)**

COMBINED PACKAGE PROJECT COST ESTIMATE UPDATE SHEET

Transmission Owner:	Central Maine Power Co.	RSP Project #:	Various
Project Name:	MPRP	Estimate Grade:	D (Construction)
Base Estimate:	\$ 1,306,414	PPA Approval:	
TCA Application #:	CMP-08-TCA-01 & CMP-10-TCA-01	Date:	6/28/2012

1. Project Scope Summary

Central Maine Power is modernizing its 40 year-old bulk power transmission system by investing between \$1.40 and \$1.51 billion in new construction. The proposed improvements are intended to maintain reliability over the coming decades and to provide the infrastructure necessary to facilitate the state's emerging wind, hydro, biomass and tidal energy industries. The Maine Power Reliability Program will improve the company's electric transmission network primarily between the towns of Eliot and Orrington where it interconnects to transmission systems in northern and eastern Maine. The Program is segregated into logical construction areas referred to as the Northern Loop, Central Loop, Southern Loop and Southern Connector.

2. Project Update

The MPRP received its ISO-NE determination letters on October 9, 2009 and January 29, 2010. The Order from the Maine Public Utilities Commission (MPUC) was approved with stipulation on June 10, 2010. Approvals by the Maine Department of Environmental Protection (MDEP) were received on April 5, 2010 and the by the Army Corps of Engineers (ACOE) on July 21, 2010. Right-of-Way (ROW) clearing is nearly complete in all construction areas. Construction access roads and environmental controls continue to be installed by the T-line contractors. T-line construction has advanced ahead of schedule during the past year, due in part to favorable weather conditions. Site development is nearly complete at the major substations with construction in progress. Portions of certain projects deferred by MPUC need to be completed as part of the current MPRP scope of work. The previous Project Forecast, in the amount of \$1.416B, included the cost of the additional scope. The current forecast of \$1.405B assumes that all work can be accomplished within the estimate submitted to the MPUC.

3. Project Cost Summary

Central Maine Power - Maine Power Reliability Program							
Project MPRP Components	Base Estimate	Base Estimate With Contingency	Scope Change	Actual Costs	Project Forecast	Estimated % Completion	Forecast vs. Estimate
2.2.1 New 345KV Lines	\$ 430,524	\$ 497,860	\$ -	\$ 149,326	\$ 497,860	30%	\$ 0
2.2.2 New 115KV Lines	\$ 190,722	\$ 220,777	\$ -	\$ 109,115	\$ 220,777	49%	\$ 0
2.2.3 New 345KV Substations	\$ 212,010	\$ 245,169	\$ -	\$ 147,281	\$ 245,170	60%	\$ 0
2.2.4 New 115KV Substations	\$ 44,328	\$ 51,311	\$ -	\$ 19,167	\$ 51,311	37%	\$ 0
2.2.5 345 KV Substations Expansions/Modifications	\$ 74,632	\$ 86,322	\$ -	\$ 57,717	\$ 86,322	67%	\$ 0
2.2.6 115 KV Substations Expansions/Modifications	\$ 18,726	\$ 21,668	\$ -	\$ 14,242	\$ 21,668	66%	\$ 0
2.2.7 Lines Rerates, Relocations, Rebuilds	\$ 335,472	\$ 389,015	\$ 3,500	\$ 138,688	\$ 389,015	36%	\$ 0
Grand Total	\$ 1,306,414	\$ 1,512,122	\$ 3,500	\$ 635,536	\$ 1,512,122	42.03%	\$ 0

Note: PTD Through the First Quarter of 2012

4. Project Forecast

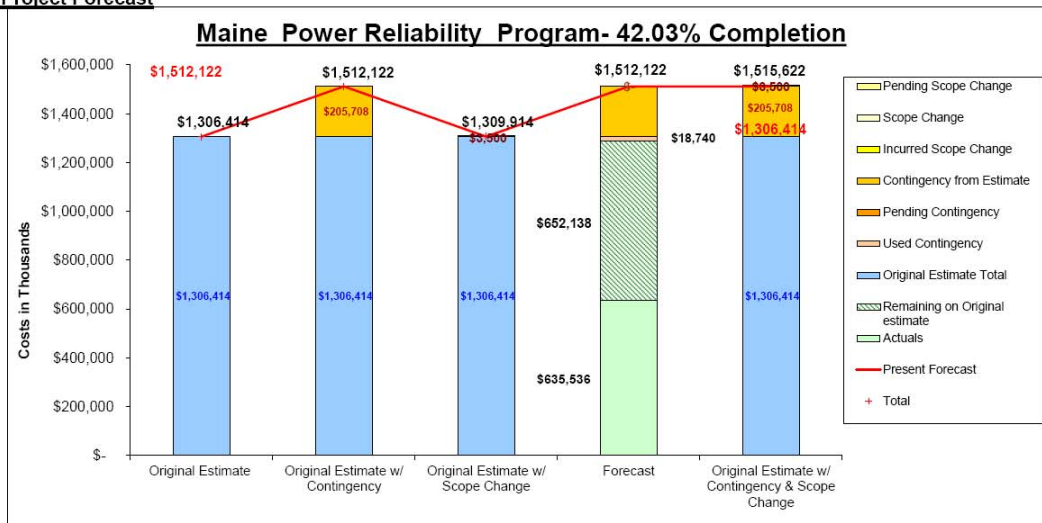


**FIGURE 2 – MPRP SETTLEMENT PROJECTS
(APPROVED BY THE MPUC)**

SETTLEMENT PACKAGE PROJECT COST ESTIMATE UPDATE SHEET

Transmission Owner:	Central Maine Power Co.	RSP Project #:	Various
Project Name:	MPRP	Estimate Grade:	D (Construction)
Base Estimate:	\$ 1,214,222	PPA Approval:	
TCA Application #:	CMP-08-TCA-01 & CMP-10-TCA-01	Date:	6/28/2012

1. Project Scope Summary

Central Maine Power is modernizing its 40 year-old bulk power transmission system by investing between \$1.40 and \$1.51 billion in new construction. The proposed improvements are intended to maintain reliability over the coming decades and to provide the infrastructure necessary to facilitate the state's emerging wind, hydro, biomass and tidal energy industries. The Maine Power Reliability Program will improve the company's electric transmission network primarily between the towns of Eliot and Orrington where it interconnects to transmission systems in northern and eastern Maine. The Program is segregated into logical construction areas referred to as the Northern Loop, Central Loop, Southern Loop and Southern Connector.

2. Project Update

The MPRP received its ISO-NE determination letters on October 9, 2009 and January 29, 2010. The Order from the Maine Public Utilities Commission (MPUC) was approved with stipulation on June 10, 2010. Approvals by the Maine Department of Environmental Protection (MDEP) were received on April 5, 2010 and the by the Army Corps of Engineers (ACOE) on July 21, 2010. Right-of-Way (ROW) clearing is nearly complete in all construction areas. Construction access roads and environmental controls continue to be installed by the T-line contractors. T-line construction has advanced ahead of schedule during the past year, due in part to favorable weather conditions. Site development is nearly complete at the major substations with construction in progress. Portions of certain projects deferred by MPUC need to be completed as part of the current MPRP scope of work. The previous Project Forecast, in the amount of \$1.416B, included the cost of the additional scope identified through design. The current forecast of \$1.405B assumes that all work can be accomplished within the estimate submitted to the MPUC.

3. Project Cost Summary

Central Maine Power - Maine Power Reliability Program \$/1000							
Project MPRP Components	Base Estimate	Base Estimate With Contingency	Scope Change	Actual Costs	Project Forecast	Estimated % Completion	Forecast vs. Estimate
2.2.1 New 345KV Lines	\$ 430,524	\$ 497,860	\$ -	\$ 149,326	\$ 497,860	30%	\$ 0
2.2.2 New 115KV Lines	\$ 155,376	\$ 179,677	\$ -	\$ 106,755	\$ 179,677	59%	\$ 0
2.2.3 New 345KV Substations	\$ 212,010	\$ 245,169	\$ -	\$ 147,281	\$ 245,170	60%	\$ 0
2.2.4 New 115KV Substations	\$ 36,416	\$ 42,111	\$ -	\$ 17,917	\$ 42,111	43%	\$ 0
2.2.5 345 KV Substations Expansions/Modifications	\$ 70,160	\$ 81,122	\$ -	\$ 57,717	\$ 81,122	71%	\$ 0
2.2.6 115 KV Substations Expansions/Modifications	\$ 15,630	\$ 18,068	\$ -	\$ 13,382	\$ 18,068	74%	\$ 0
2.2.7 Lines Rerates, Relocations, Rebuilds	\$ 294,106	\$ 340,915	\$ 3,500	\$ 138,688	\$ 340,915	41%	\$ 0
Grand Total	\$ 1,214,222	\$ 1,404,922	\$ 3,500	\$ 631,066	\$ 1,404,922	44.92%	\$ 0

Note: PTD Through the First Quarter of 2012

4. Project Forecast

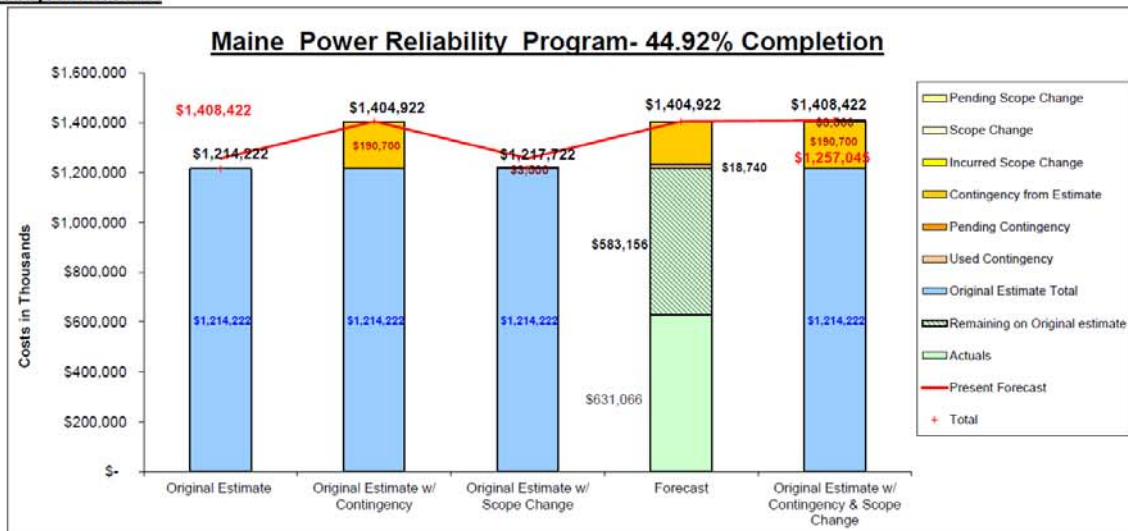


**FIGURE 3 – MPRP DEFERRED & OMITTED PROJECTS
(PENDING ADDITIONAL REGULATORY REVIEW AND APPROVAL)**

DEFERRED PACKAGE PROJECT COST ESTIMATE UPDATE SHEET

Transmission Owner:	Central Maine Power Co.	RSP Project #:	Various
Project Name:	Maine Power Reliability Program	Estimate Grade:	D (Construction)
Base Estimate:	\$ 92,192	PPA Approval:	
TCA Application #:	CMP-08-TCA-01 & CMP-10-TCA-01	Date:	6/28/2012

1. Project Scope Summary

Central Maine Power is modernizing its 40 year-old bulk power transmission system by investing between \$1.40 and \$1.51 billion in new construction. The proposed improvements are intended to maintain reliability over the coming decades and to provide the infrastructure necessary to facilitate the state's emerging wind, hydro, biomass and tidal energy industries. The Maine Power Reliability Program will improve the company's electric transmission network primarily between the towns of Elliot and Orrington where it interconnects to transmission systems in northern and eastern Maine. The Program is segregated into logical construction areas referred to as the Northern Loop, Central Loop, Southern Loop and Southern Connector.

2. Project Update

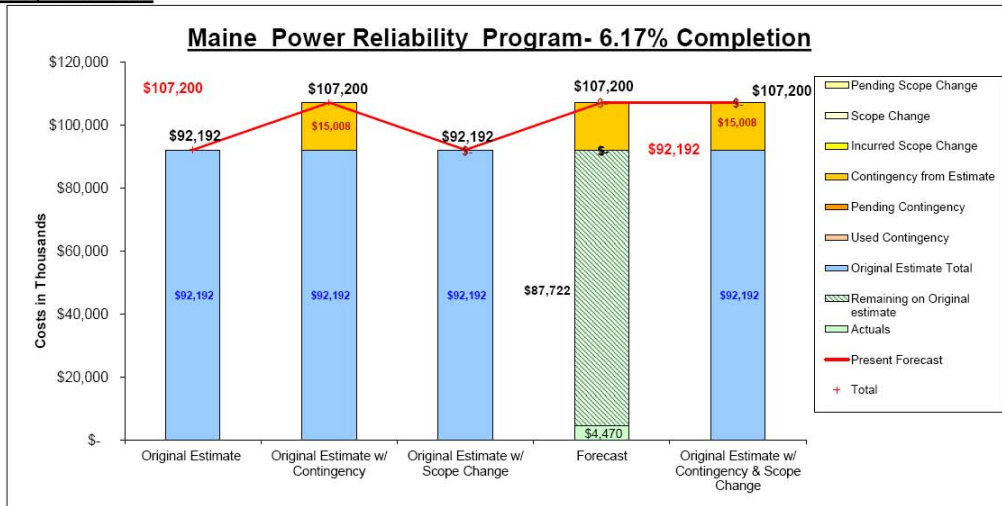
The MPRP received its ISO-NE determination letters on October 9, 2009 and January 29, 2010. The Order from the Maine Public Utilities Commission (MPUC) was approved with stipulation on June 10, 2010. Approvals by the Maine Department of Environmental Protection (MDEP) were received on April 5, 2010 and the by the Army Corps of Engineers (ACOE) on July 21, 2010. Right-of-Way (ROW) clearing is nearly complete in all construction areas. Construction access roads and environmental controls continue to be installed by the T-line contractors. T-line construction has advanced ahead of schedule during the past year, due in part to favorable weather conditions. Site development is nearly complete at the major substations with construction in progress. Portions of certain projects deferred by MPUC need to be completed as part of the current MPRP scope of work. The previous Deferred Project Forecast, in the amount of \$88.6M has been realigned to the program component categories and original TCA estimates. The current forecast of \$107.2M has been adjusted for new cost projections based on material pricing, construction contract values and estimates. Section 3020 was approved by the MPUC under separate CPCN and is now included in the Settlement project report.

3. Project Cost Summary

Central Maine Power - Maine Power Reliability Program							
Project Maine Power Reliability Program Components	Base Estimate	Base Estimate With Contingency	Scope Change	Actual Costs	Project Forecast	Estimated % Completion	Forecast vs. Estimate
2.2.1 New 345KV Lines	\$ -	\$ -	\$ -	\$ -	\$ -	0%	\$ -
2.2.2 New 115KV Lines	\$ 35,346	\$ 41,100	\$ -	\$ 2,360	\$ 41,100	6%	\$ -
2.2.3 New 345KV Substations	\$ -	\$ -	\$ -	\$ -	\$ -	0%	\$ -
2.2.4 New 115KV Substations	\$ 7,912	\$ 9,200	\$ -	\$ 1,250	\$ 9,200	14%	\$ -
2.2.5 345 KV Substations Expansions/Modifications	\$ 4,472	\$ 5,200	\$ -	\$ -	\$ 5,200	0%	\$ -
2.2.6 115 KV Substations Expansions/Modifications	\$ 3,096	\$ 3,600	\$ -	\$ 860	\$ 3,600	24%	\$ -
2.2.7 Lines Rerates, Relocations, Rebuilds	\$ 41,366	\$ 48,100	\$ -	\$ -	\$ 48,100	0%	\$ -
Grand Total	\$ 92,192	\$ 107,200	\$ -	\$ 4,470	\$ 107,200	6.17%	\$ -

Note: PTD Through the First Quarter of 2012

4. Project Forecast



APPENDIX A – PROGRAM COST SUMMARY



MAINE POWER RELIABILITY PROGRAM (MPRP)
Program Cost Summary \$'000
as of 15-Jun-12



Settlement

Calendar Year	Pre 2012 Total	2012												2012 Total	2013 Total	2014 Total	2015 Total	TOTAL
		January	February	March	April	May	June	July	August	September	October	November	December					
Material	\$ 82,316	\$ 11,046	\$ 9,803	\$ 5,330	\$ 7,003	\$ 6,746	\$ 6,591	\$ 6,678	\$ 10,504	\$ 5,061	\$ 9,770	\$ 9,446	\$ 4,277	\$ 92,255	\$ 17,909	\$ 12,393	\$ -	\$ 204,873
Labor	\$ 215,925	\$ 13,870	\$ 10,832	\$ 14,849	\$ 10,820	\$ 11,246	\$ 13,367	\$ 16,412	\$ 13,322	\$ 15,377	\$ 11,407	\$ 9,091	\$ 11,387	\$ 151,781	\$ 159,877	\$ 62,192	\$ 15,030	\$ 604,805
Right of Way (net)	\$ 33,387	\$ (127)	\$ (92)	\$ (143)	\$ 12	\$ 1	\$ 6,747	\$ 5	\$ (99)	\$ (150)	\$ (175)	\$ -		\$ 5,979	\$ (893)	\$ (750)	\$ -	\$ 37,723
Engineering / Permitting / Indirects	\$ 194,441	\$ 1,794	\$ 5,467	\$ 4,075	\$ 5,371	\$ 3,590	\$ (2,276)	\$ 3,408	\$ 3,623	\$ 3,466	\$ 3,362	\$ 3,207	\$ 3,643	\$ 38,750	\$ 21,681	\$ 21,498	\$ 18,016	\$ 294,386
Escalation	\$ -	\$ 1,855	\$ 1,500	\$ 1,804	\$ 1,498	\$ 1,548	\$ 1,787	\$ 2,088	\$ 1,782	\$ 1,991	\$ 1,567	\$ 1,296	\$ 1,194	\$ 20,000	\$ 27,000	\$ 21,800	\$ 3,500	\$ 72,300
AFUDC	\$ 134	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 134
Contingency	\$ 15,390	\$ 2,886	\$ 2,333	\$ 2,500	\$ 2,331	\$ 2,408	\$ 2,700	\$ 2,700	\$ 2,700	\$ 2,750	\$ 2,438	\$ 2,017	\$ 2,434	\$ 30,196	\$ 40,000	\$ 100,814	\$ 4,300	\$ 190,700
Total	\$ 541,593	\$ 31,324	\$ 29,843	\$ 28,305	\$ 27,035	\$ 25,540	\$ 28,916	\$ 31,291	\$ 31,832	\$ 28,495	\$ 28,389	\$ 25,057	\$ 22,935	\$ 338,962	\$ 265,574	\$ 217,947	\$ 40,846	\$ 1,404,922

Deferred

Calendar Year	Pre 2012 Total	2012												2012 Total	2013 Total	2014 Total	2015 Total	TOTAL
		January	February	March	April	May	June	July	August	September	October	November	December					
Material	\$ 841													\$ -	\$ 4,332	\$ 19,500	\$ 1,000	\$ 25,673
Labor	\$ 195													\$ -	\$ 9,425	\$ 13,750	\$ 12,477	\$ 35,647
Right of Way	\$ 1,201													\$ -	\$ -	\$ -	\$ -	\$ 1,201
Engineering / Permitting / Indirects	\$ 2,092	\$ 25	\$ 25	\$ 44	\$ -	\$ -	\$ 5	\$ 14	\$ 9	\$ 4	\$ -	\$ -	\$ -	\$ 128	\$ 6,312	\$ 8,949	\$ 7,187	\$ 24,696
Escalation														\$ -	\$ 1,070	\$ 1,843	\$ 800	\$ 3,713
AFUDC	\$ 44	\$ 1.0	\$ 1.0	\$ 1.0	\$ 1.0	\$ 1.0	\$ 1.0	\$ 1.0	\$ 1.0	\$ 1.0	\$ 1.0	\$ 1.0	\$ 1.0	\$ 12	\$ -	\$ -	\$ -	\$ 56
Contingency	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 2,804	\$ 10,010	\$ 3,230	\$ 16,044
Total	\$ 4,373	\$ 26	\$ 26	\$ 45	\$ 1	\$ 1	\$ 6	\$ 15	\$ 10	\$ 5	\$ 1	\$ 1	\$ 1	\$ 138	\$ 23,943	\$ 54,052	\$ 24,694	\$ 107,200

Combined

Calendar Year	Pre 2012 Total	2012												2012 Total	2013 Total	2014 Total	2015 Total	TOTAL
		January	February	March	April	May	June	July	August	September	October	November	December					
Material	\$ 83,157	\$ 11,046	\$ 9,803	\$ 5,330	\$ 7,003	\$ 6,746	\$ 6,591	\$ 6,678	\$ 10,504	\$ 5,061	\$ 9,770	\$ 9,446	\$ 4,277	\$ 92,255	\$ 22,241	\$ 31,893	\$ 1,000	\$ 230,546
Labor	\$ 216,120	\$ 13,870	\$ 10,832	\$ 14,849	\$ 10,820	\$ 11,246	\$ 13,367	\$ 16,412	\$ 13,322	\$ 15,377	\$ 11,407	\$ 9,091	\$ 11,387	\$ 151,781	\$ 169,302	\$ 75,942	\$ 27,507	\$ 640,652
Right of Way	\$ 34,588	\$ (127)	\$ (92)	\$ (143)	\$ 12	\$ 1	\$ 6,747	\$ 5	\$ (99)	\$ (150)	\$ (175)	\$ -	\$ -	\$ 5,979	\$ (893)	\$ (750)	\$ -	\$ 38,924
Engineering / Permitting / Indirects	\$ 196,533	\$ 1,819	\$ 5,492	\$ 4,119	\$ 5,371	\$ 3,590	\$ (2,271)	\$ 3,422	\$ 3,632	\$ 3,470	\$ 3,362	\$ 3,207	\$ 3,643	\$ 38,876	\$ 27,993	\$ 30,447	\$ 25,203	\$ 319,052
Escalation	\$ -	\$ 1,855	\$ 1,500	\$ 1,894	\$ 1,498	\$ 1,548	\$ 1,787	\$ 2,088	\$ 1,782	\$ 1,991	\$ 1,567	\$ 1,296	\$ 1,194	\$ 20,000	\$ 28,070	\$ 23,643	\$ 4,300	\$ 76,013
AFUDC	\$ 178	\$ 1	\$ 1	\$ 1	\$ 1	\$ 1	\$ 1	\$ 1	\$ 1	\$ 1	\$ 1	\$ 1	\$ 1	\$ 12	\$ -	\$ -	\$ -	\$ 190
Contingency	\$ 15,390	\$ 2,886	\$ 2,333	\$ 2,500	\$ 2,331	\$ 2,408	\$ 2,700	\$ 2,700	\$ 2,700	\$ 2,750	\$ 2,438	\$ 2,017	\$ 2,434	\$ 30,196	\$ 42,804	\$ 110,824	\$ 7,530	\$ 206,744
Total	\$ 545,966	\$ 31,350	\$ 29,869	\$ 28,350	\$ 27,036	\$ 25,541	\$ 28,922	\$ 31,306	\$ 31,842	\$ 28,500	\$ 28,390	\$ 25,058	\$ 22,936	\$ 339,100	\$ 289,517	\$ 271,999	\$ 65,540	\$ 1,512,122

APPENDIX B – MPRP COSTS THROUGH 2012 FOR CWIP FILING

MPRP Costs For 2012 for CWIP Filing

	PTF	Non-PTF	Distribution	Total
Projected Additional CWIP for 2012	\$ (11,476,279)	\$ 4,605,014		\$ (6,871,265)
Additional In Service 2012	\$ 328,258,236	\$ 5,329,920		\$ 333,588,156
Retirements / Removals Costs in 2012	\$ 9,955,024	\$ 194,401	\$ -	\$ 10,149,425
Total	\$ 326,736,981	\$ 10,129,335	\$ -	\$ 336,866,316
CWIP Year End 2012	\$ 458,463,718	\$ 9,901,189		\$ 468,364,907
In Service 2012	\$ 329,287,225	\$ 4,428,004		\$ 333,715,229
In Service Year End 2011	\$ 54,775,636	\$ 4,063,993		\$ 58,839,629
			\$ -	\$ -
Total In Service through 2012	\$ 384,062,861	\$ 8,491,997	\$ -	\$ 392,554,858

CMEEC
Revenue Required and Support Payment Summary
For Year 2011
Submitted May 14, 2012

Support Payments / Revenue Requirements	Pre-97	Post-96	Total
Support Payments to New England Power Company for Hydro-Quebec Phase II A.C. Transmission Facilities (Attachment F, Item K)	\$ 54,565.55		\$ 54,565.55
Support Payments to Boston Edison Company for Hydro-Quebec Phase II A.C. Transmission Facilities (Attachment F, Item K)	\$ 3,808.00		\$ 3,808.00
Support Payments to New England Hydro-Transmission Corporation for Hydro-Quebec Phase II Chester SVC Facility (Attachment F, Item K)	\$ 23,172.75		\$ 23,172.75
Revenue Requirements for Bozrah Light and Power PTF Facilities		\$99,204	\$ 99,204.00
Revenue Requirements for City of Groton, Department of Utilities PTF Facilities		\$209,046	\$ 209,046.00
Revenue Requirements for Norwich, Department of Utilities PTF Facilities	\$238,105		\$ 238,105.00
Revenue Requirements for Town of Wallingford, Electric Div. PTF Facilities	\$96,820	\$590,788	\$ 687,608.00
Revenue Requirements for Mohegan Tribal Utility Authority PTF Facilities		\$311,984	\$ 311,984.00
Total Support Payments and Revenue Requirements Less Revenues	\$416,471	\$1,211,022	\$ 1,627,493.30

Bozrah Voting Share

Regional Network Service Annual Transmission Revenue Requirements per Tariff Attachment F of the ISO New England Inc. Open Access Transmission Tariff

Shading denotes an input

Submitted on: May 14, 2012

Revenue Requirements based on Year Ending: June 30, 2011

Rate Effective for the period:
Through: June 1, 2012
May 31, 2013

Customer: Bozrah Light and Power

Customer's NABs Number: 8

Name of Participant responsible for customer's billing: CMEEC

DUNs number of Participant responsible for customer's billing: 09-207-8351

	Pre-97 Revenue Requirements	Post-97 Revenue Requirements
Total of Attachment F - Sections A through I =	<u>0</u> (a)	<u>65,201</u> (f)
Total of Attachment F - Section J - Support Revenue	<u>0</u> (b)	<u>0</u> (g)
Total of Attachment F - Section K - Support Expense	<u>0</u> (c)	<u>0</u> (h)
Total of Attachment F - Section (L through O)	<u>0</u> (d)	<u>0</u> (i)
Sub Total - Sum (A through I) - J + K + (L through O)	<u>0</u> (e)=(a)-(b)+(c)+(d)	<u>65,201</u> (j)=(f)-(g)+(h)+(i)
Forecasted Transmisison Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	<u>0</u>	<u>28,628</u> (k)
Annual True-up (per attachment C to Attachemnet F Implementation f	<u>0</u>	<u>5,375</u> (l)
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:		<u><u>99,204</u></u> (m) = (e)+(j)+(k)+(l)
Total of Attachment F - Section J - Pre-97 Support Revenue (from above)		<u>0</u> =(b)
Total of Attachment F - Section J - Post-96 Support Revenue (from above-)		<u>0</u> =(g)
Total of Attachment F - Section K - Post-96 Support Expense (from above)		<u>0</u> =(h)
Voting Share Total for Participant's R Value: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)		<u><u>99,204</u></u> =(m)

Shading denotes an input

		Attachment F	Bozrah Light and Power	
Line No.		Reference		Reference
I. INVESTMENT BASE		Section:		
1	Transmission Plant	(A)(1)(a)	637,144	Worksheet 3, L10
2	General Plant	(A)(1)(b)	0	Worksheet 3, L11
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3, L14
4	Total Plant (Lines 1+2+3)		637,144	
5	Accumulated Depreciation	(A)(1)(d)	0	Worksheet 3, L19
6	Accumulated Deferred Income Taxes	(A)(1)(e)	0	Worksheet 3, L24
7	Loss On Reacquired Debt	(A)(1)(f)	0	Worksheet 3, L26
8	Other Regulatory Assets	(A)(1)(g)	0	Worksheet 3, L32
9	Net Investment (Line 4-5-6+7+8)		637,144	
10	Prepayments	(A)(1)(h)	0	Worksheet 3, L34
11	Materials & Supplies	(A)(1)(i)	4,798	Worksheet 3, L36
12	Cash Working Capital	(A)(1)(j)	9	Worksheet 3, 44
13	Total Investment Base (Line 9+10+11+12)		641,951	
II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	51,356	Worksheet 2, E56
15	Depreciation Expense	(B)	0	Worksheet 4, L12
16	Amortization of Loss on Reacquired Debt	(C)	0	Worksheet 4, L14
17	Investment Tax Credit	(D)	0	Worksheet 4, L16
18	Property Tax Expense	(E)	13,771	Worksheet 4, L21
19	Payroll Tax Expense	(F)	0	Worksheet 4, L42
20	Operation & Maintenance Expense	(G)	0	Worksheet 4, L29
21	Administrative & General Expense	(H)	74	Worksheet 4, L40
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	0	Worksheet 7, E51
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	0	
28	Transmission Rents Received from Electric Property	(O)	0	
29	Total Revenue Requirements (Line 14 thru 28)		65,201	

Shading denotes an input

	CAPITALIZATION 2011		CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 0		0.00%	0.00%	0.00%	
PREFERRED STOCK	0		0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	6,241,237		100.00%	8.00%	8.00%	8.00%
TOTAL INVESTMENT RETURN	\$ 6,241,237		100.00%		8.00%	8.00%
	(PTF)					
INVESTMENT BASE	\$ 641,951	From Worksheet 1				
x Cost of Capital Rate	8.00%					
= Investment Return and Income Taxes	51,356	To Worksheet 1				

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Reference
<u>Transmission Plant</u>						
1	853,124		853,124		637,144	
2	1,262,116	0.0000% (a)	0	74.6836%	0	DPUC Report-Page 502
3			853,124		637,144	
4	0		0	74.6836%	0	None known
<u>Transmission Accumulated Depreciation</u>						
5	0		0	74.6836%	0	2010 first recording of transmissio nplant, no depreciation reported page 200 DPUC report line 3(d)
6	66,917	0.0000% (a)	0	74.6836%	0	
7			0		0	
<u>Transmission Accumulated Deferred Taxes</u>						
8	0	5.3595% (c)	0	74.6836%	0	Not applicable.
9	0	5.3595% (c)	0	74.6836%	0	Not applicable.
10	0		0		0	
11	0	5.3595% (c)	0	74.6836%	0	Not applicable.
<u>Other Regulatory Assets</u>						
12	0	0.0000% (a)	0	74.6836%	0	Not applicable.
13	0	5.3595% (c)	0	74.6836%	0	Not applicable.
14	0	5.3595% (c)	0	74.6836%	0	Not applicable.
15	0		0		0	
16	0	0.0000% (a)	0	74.6836%	0	Assumed none
17	119,868	5.3595%	6,424	74.6836%	4,798	DPUC report-Page 200
<u>Cash Working Capital</u>						
19					0	Worksheet 1, Line 20
20					74	Worksheet 1, Line 21
21					0	Worksheet 1, Line 24
22					74	
23					0.125	x 45 / 360
24					9	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Reference
<u>Depreciation Expense</u>						
1			0	74.6836%	0	DPUC Report Page 200
2	66,917	0.0000% (a)	0	74.6836%	0	
3			0		0	
4	0	5.3595% (c)	0	74.6836%	0	None known
5	0	5.3595% (c)	0	74.6836%	0	None known
<u>Property Taxes *</u>						
6	344,045	5.3595%	18,439	74.6836%	13,771	See below
7	0	0.0000% (a)	0	74.6836%	0	See below
8			18,439		13,771	
<u>Transmission Operation and Maintenance</u>						
9	0		0	74.6836%	0	DPUC Report-Page 518 embedded in lline 23 page
10	0		0	74.6836%	0	
11	0		0	74.6836%	0	
12	0		0	74.6836%	0	DPUC Report-Page 518
13	0		0	74.6836%	0	
<u>Transmission Administrative and General</u>						
14	337,545					DPUC Report-Page 520
15	1,843					DPUC Report-Page 520
16	2,150					
17	10,005					assumed none
18	323,547	0.0000% (a)	0	74.6836%	0	
19	1,843	5.3595% (c)	99	74.6836%	74	
20	0	5.3595% (c)	0	74.6836%	0	
21	0	5.3595% (c)	0	74.6836%	0	
22	325,390		99		74	
23	37,423	0.0000% (a)	0	74.6836%	0	Footnote (d)
(a) Worksheet 5 of 8, line 11						
(b) Worksheet 5 of 8, line 3						
(c) Worksheet 5 of 8, line 16						
(d) Payroll taxes						
Federal Unemployment	0	assumed none for simplicity				
FICA	37,423	DPUC Report Page 219				
Medicare	0	assumed none for simplicity				
CT Unemployment	0	assumed none for simplicity				
MA Unemployment	0	assumed none for simplicity				
MA Universal Health	0	assumed none for simplicity				
VT Unemployment	0	assumed none for simplicity				
NH Unemployment	0	assumed none for simplicity				
Total	37,423	To Line 23				

** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments.

Shading denotes an input

Line
No.

PTF Transmission Plant Allocation Factor

Bozrah Light and Power

Reference

1	PTF Transmission Investment	637,144	from excel worksheet - B Roche
2	Total Transmission Investment	853,124	DPUC Report-Page 501 + \$637144.25 PTF in serv
3	Percent Allocation (Line 1/Line 2)	74.6836%	

Transmission Wages and Salaries Allocation Factor

4	Direct Transmission Wages and Salaries	0	DPUC Report-Page 507
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 of 8
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	0	
7	Total Wages and Salaries	638,916	DPUC Report-Page 507
8	Administrative and General Wages and Salaries	78,508	DPUC Report-Page 507
9	Affiliated Company Wages and Salaries less A&G	0	Worksheet 6 of 8
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	560,408	
11	Percent Allocation (Line 6/Line 10)	0.0000%	

Plant Allocation Factor

12	Total Transmission Investment	853,124	Worksheet 3, Line 1
13	plus Transmission-Related General Plant (Line 2 of Wkst. 3)	0	Worksheet 3, Line 2, col 3
14	= Revised Numerator (Line 12 + Line 13)	853,124	
15	Total Plant in Service	15,917,933	DPUC Report-Page 502
16	Percent Allocation (Line 14 / Line 15)	5.3595%	

Affiliated Company Wages and Salaries

Shading denotes an input

Line		Bozrah Light and Power
"Affiliated" Transmission Wages and Salaries #560 - 573		
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11 = 1 thru 10	Total Transmission	0
12 = Total "Affiliated" Wages and Salaries		
Less "Affiliated" Administrative and General Salaries #920 - 935		
13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
21 = 13 thru 20		0
22 = 12 less 21	Total "Affiliated" less A&G	0

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	FERC Form 1	TOTAL	
			Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	332.(g); [332.1(g) for HWP]		0
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			0
	Comerford 115 kV Substation			
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	332.1(g); [332(g) for CL&P]		0
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 394 line	332(g)		
	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			0
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310 line	330.1(n)		
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
Total =			0	0

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

CMEEC
Bozrah Light and Power
For costs In 2012
FORECAST

Shading denotes an input

Attachment F
 Regerence

I. FORECASTED TRANSMISSION REVENUE REQUIREMENTS Period Section: POST-1996 Reference

Line No,

1	Forecasted Transmission Plant Additions	2012 Appendix C	357,856	difference of estimated tc
2	Carrying Charge Factor		8.00%	
3	Total Forecasted Revenue Requirements (Lines 1*2)		28,628	

Bozrah Light & Power
FERC Interest Calculation associated with Under / (Over)
True Up and Interest Calculation for 2011

Line	Annual True-up	Pre 1997	Post 1996	Total	
1	Transmission Revenue Requirements (as billed)		60,000	\$ 60,000	ATRR - Prior Year
2	True-up 2011 Actual Annual RR		65,201	\$ 65,201	PTF Pre & Post on ATRR
3	True-up Surcharge / (Refund) (Line 2 - 1)	-	5,201	\$ 5,201	

	Surcharge / (Refund)
Pre 1997	\$ -
Post 1996	\$ 5,201

Initial Billing	Balance		FERC Monthly Interest	Interest	
Period	Pre 1997	Post 1996	Rate	Pre 1997	Post 1996
June 2011	\$ -	\$ 5,201	0.27%	\$ -	\$ 14
July 2011	\$ -	\$ 5,215	0.27%	\$ -	\$ 14
August 2011	\$ -	\$ 5,215	0.28%	\$ -	\$ 15
September 2011	\$ -	\$ 5,215	0.27%	\$ -	\$ 14
October 2011	\$ -	\$ 5,258	0.28%	\$ -	\$ 15
November 2011	\$ -	\$ 5,258	0.27%	\$ -	\$ 14
December 2011	\$ -	\$ 5,258	0.28%	\$ -	\$ 15
January 2012	\$ -	\$ 5,302	0.28%	\$ -	\$ 15
February 2012	\$ -	\$ 5,302	0.26%	\$ -	\$ 14
March 2012	\$ -	\$ 5,302	0.28%	\$ -	\$ 15
April 2012	\$ -	\$ 5,346	0.27%	\$ -	\$ 14
May 2012	\$ -	\$ 5,346	0.28%	\$ -	\$ 15
Total Surcharge/ (Refund)				\$ -	\$ 5,375

	Interest	Principal	Total
Pre 1997	\$ -	\$ -	\$ -
Post 1996	\$ 174	\$ 5,201	\$ 5,375
	\$ 174	\$ 5,201	\$ 5,375

GU Voting Share
Regional Network Service
Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO New England Inc. Open Access Transmission Tariff

Shading denotes an input

Submitted on:	May 14, 2012
Revenue Requirements based on Year Ending:	June 30, 2011
Rate Effective for the period:	June 1, 2012
Through:	May 31, 2013
Customer:	City of Groton, Dept. of Utilities
Customer's NABs Number:	8
Name of Participant responsible for customer's billing:	CMEEC
DUNS number of Participant responsible for customer's billing:	09-207-8351

	Pre-97 Revenue Requirements	Post-96 Revenue Requirements
Total of Attachment F - Sections A through I =	0 (a)	209,046 (f)
Total of Attachment F - Section J - Support Revenue	0 (b)	0 (g)
Total of Attachment F - Section K - Support Expense	0 (c)	0 (h)
Total of Attachment F - Section (L through O)	0 (d)	0 (i)
Sub Total - Sum (A through I) - J + K + (L through O)	0 (e)=(a)-(b)+(c)+(d)	209,046 (j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	0	(k)
Annual True-up (per Attachment C to Attachment F Implementation Rule)	0	0 (m)
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:		209,046 (l) = (j)+(k)+(m)
Total of Attachment F - Section J - Pre-97 Support Revenue (from above)		0 (b)
Total of Attachment F - Section J - Post-96 Support Revenue (from above-)		0 (g)
Total of Attachment F - Section K - Post-96 Support Expense (from above)		0 (h)
Voting Share Total for Participant's R Value: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)		<u>209,046 (l)=(o)+(b)+(g)-(h)</u>

	Shading denotes an input
	Modified since last filing
	Value changed by modification

		Attachment F		
		Reference	GROTON	Reference
Line No.	I. INVESTMENT BASE	Section:		
1	Transmission Plant	(A)(1)(a)	2,463,503	Worksheet 3, L10
2	General Plant	(A)(1)(b)	36,225	Worksheet 3, L11
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3, L14
4	Total Plant (Lines 1+2+3)		2,499,728	
5	Accumulated Depreciation	(A)(1)(d)	2,175,298	Worksheet 3, L19
6	Accumulated Deferred Income Taxes	(A)(1)(e)	0	Worksheet 3, L24
7	Loss On Reacquired Debt	(A)(1)(f)	0	Worksheet 3, L26
8	Other Regulatory Assets	(A)(1)(g)	0	Worksheet 3, L32
9	Net Investment (Line 4-5-6+7+8)		324,430	
10	Prepayments	(A)(1)(h)	0	Worksheet 3, L34
11	Materials & Supplies	(A)(1)(i)	71,510	Worksheet 3, L36
12	Cash Working Capital	(A)(1)(j)	5,842	Worksheet 3, 44
13	Total Investment Base (Line 9+10+11+12)		401,782	
II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	32,143	Worksheet 2, E56
15	Depreciation Expense	(B)	67,207	Worksheet 4, L3
16	Amortization of Loss on Reacquired Debt	(C)	0	Worksheet 4, L4
17	Investment Tax Credit	(D)	0	Worksheet 4, L5
18	Property Tax Expense	(E)	61,380	Worksheet 4, L8
19	Payroll Tax Expense	(F)	1,578	Worksheet 4, L23
20	Operation & Maintenance Expense	(G)	23,233	Worksheet 4, L13
21	Administrative & General Expense	(H)	23,505	Worksheet 4, L22
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	0	Worksheet 7, E51
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	0	
28	Transmission Rents Received from Electric Property	(O)	0	
29	Total Revenue Requirements (Line 14 thru 28)		209,046	

Shading denotes an input
Modified since last filing
Value changed by modification

	CAPITALIZATION 12/31/2010		CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
		May 18, 2011				
LONG-TERM DEBT	\$ 0	Per 2002 NEPOOL Interpretive Guidance Document (part	0.00%	6.03%	0.00%	
PREFERRED STOCK	0	of Muni RNS audit total investment return should = 8%)	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	13,537,328	DPUC Rpt. P. 201, line 11	100.00%	8.00%	8.00%	8.00%
TOTAL INVESTMENT RETURN	\$ 13,537,328		100.00%		8.00%	8.00%
	(PTF)					
INVESTMENT BASE	\$ 401,782	From Worksheet 1				
x Cost of Capital Rate	8.00%					
= Investment Return and Income Taxes	32,143	To Worksheet 1				

City of Groton, Dept. of Utilities

PTF Revenue Requirements
Worksheet 3 of 7

Shading denotes an input
Modified since last filing
Value changed by modification

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Reference
<u>Transmission Plant</u>						
1	7,964,062		7,964,062		\$ 2,463,503	
2	8,026,107	1.4591% (a)	117,109	30.9327%	36,225	DPUC Report-Page 502
3			8,081,171	May 18, 2011	2,499,728	
4	0		0	30.9327%	0	None known
<u>Transmission Accumulated Depreciation</u>						
5	6,956,631		6,956,631	30.9327%	2,151,874	see depreciation tab
6	5,189,908	1.4591% (a)	75,726	30.9327%	23,424	see depreciation tab
7			7,032,357		2,175,298	
<u>Transmission Accumulated Deferred Taxes</u>						
8	0	12.9719% (c)	0	30.9327%	0	None known
9	0	12.9719% (c)	0	30.9327%	0	None known
10			0		0	
11	0	12.9719% (c)	0	30.9327%	0	None known
<u>Other Regulatory Assets</u>						
12	0	1.4591% (a)	0	30.9327%	0	None known
13	0	12.9719% (c)	0	30.9327%	0	None known
14	0	12.9719% (c)	0	30.9327%	0	
15	0		0		0	
16	0	1.4591% (a)	0	30.9327%	0	Assumed none
17	1,782,149	12.9719%	231,179	30.9327%	71,510	DPUC report-Page 200
<u>Cash Working Capital</u>						
19					23,233	Worksheet 1, Line 20
20					23,505	Worksheet 1, Line 21
21					0	Worksheet 1, Line 24
22					46,738	
23					0.125	x 45 / 360
24					5,842	

(a) Worksheet 5 of 8, line 11
(b) Worksheet 5 of 8, line 3
(c) Worksheet 5 of 8, line 16

City of Groton, Dept. of Utilities

Shading denotes an input
Modified since last filing
Value changed by modification

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Reference
<u>Depreciation Expense</u>						
1	214,120		214,120	30.9327%	66,233	see below
2	215,788	1.4591% (a)	3,149	30.9327%	974	see below
3			217,269	May 18, 2011	67,207	
4	0	12.9719% (c)	0	30.9327%	0	None known
5	0	12.9719% (c)	0	30.9327%	0	None known
<u>Property Taxes *</u>						
6	196,234		196,234	30.9327%	60,701	See below
7	150,423	1.4591% (a)	2,195	30.9327%	679	See below
8			198,429		61,380	
<u>Transmission Operation and Maintenance</u>						
9	75,107		75,107	30.9327%	23,233	DPUC Report-Page 518
10	0		0	30.9327%	0	
11	0		0	30.9327%	0	
12	0		0	30.9327%	0	DPUC Report-Page 518
13	75,107		75,107	30.9327%	23,233	
<u>Transmission Administrative and General</u>						
14	4,742,356					DPUC Report-Page 520
15	60,158					DPUC Report-Page 520
16	9,231					
17	0					assumed none
18	4,672,967	1.4591% (a)	68,183	30.9327%	21,091	
19	60,158	12.9719% (c)	7,804	30.9327%	2,414	
20	0	12.9719% (c)	0	30.9327%	0	
21	0	12.9719% (c)	0	30.9327%	0	
22	4,733,125		75,987		23,505	
23	349,737	1.4591% (a)	5,103	30.9327%	1,578	Footnote (d)

(a) Worksheet 5 of 8, line 11 (Transmission Wage & Salary Allocator)

(b) Worksheet 5 of 8, line 3 (PTF Allocator)

(c) Worksheet 5 of 8, line 16 (Plant allocator)

(d) Payroll taxes

Federal Unemployment	0	assumed none for simplicity
FICA	349,737	DPUC Report Page 219
Medicare	0	assumed none for simplicity
CT Unemployment	0	assumed none for simplicity
MA Unemployment	0	assumed none for simplicity
MA Universal Health	0	assumed none for simplicity
VT Unemployment	0	assumed none for simplicity
NH Unemployment	0	assumed none for simplicity
Total	349,737	To Line 23

** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments.

Total Transmission Plant in Service 6/30/11	7,964,062	
Less Furniture & Fixtures		
Net Taxable Plant	7,964,062	
Applicable Mill Rate	24.64	
	196,234	To cell d6 above
Total Electric Plant in Service as of 6/30/11	8,026,107	
Less Furniture & Fixtures	1,921,292	DPUC Report Page 502 Line4
Net Taxable Plant	6,104,815	
Applicable Mill Rate	24.64	
	150,423	To cell d7 above

Shading denotes an input

Line
No.

PTF Transmission Plant Allocation Factor		GROTON	Reference
1	PTF Transmission Investment	\$ 2,463,503	From Auditor's tab
2	Total Transmission Investment	7,964,062	DPUC Report-Page 501
3	Percent Allocation (Line 1/Line 2)	30.9327%	
Transmission Wages and Salaries Allocation Factor			
4	Direct Transmission Wages and Salaries	47,062	DPUC Report-Page 507
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 of 8
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	47,062	
7	Total Wages and Salaries	4,748,401	DPUC Report-Page 507
8	Administrative and General Wages and Salaries	1,523,069	DPUC Report-Page 507
9	Affiliated Company Wages and Salaries less A&G	0	Worksheet 6 of 8
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	3,225,332	
11	Percent Allocation (Line 6/Line 10)	1.4591%	
Plant Allocation Factor			
12	Total Transmission Investment	7,964,062	Line 2
13	plus Transmission-Related General Plant (Line 2 of Wkst. 3)	117,109	Worksheet 3, Line 2, Col :
14	= Revised Numerator (Line 12 + Line 13)	8,081,171	
15	Total Plant in Service	62,297,357	DPUC Report-Page 502
16	Percent Allocation (Line 14 / Line 15)	12.9719%	

Affiliated Company Wages and Salaries

Shading denotes an input

Line		GROTON
"Affiliated" Transmission Wages and Salaries #560 - 573		
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11 = 1 thru 10	Total Transmission	0
12 = Total "Affiliated" Wages and Salaries		0
Less "Affiliated" Administrative and General Salaries #920 - 935		
13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
21 = 13 thru 20		0
22 = 12 less 21	Total "Affiliated" less A&G	0

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	FERC Form 1	TOTAL	
			Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	332.(g); [332.1(g) for HWP]		0
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			0
	Comerford 115 kV Substation			
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	332.1(g); [332(g) for CL&P]		0
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 394 line	332(g)		
	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			0
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310 line	330.1(n)		
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
Total =			0	0

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

CITY OF GROTON DEPARTMENT OF UTILITIES										
			Buddington	TRANSMISSION			DISTRIBUTION			
Work order	Completion Date	Description	TOTAL	TOTAL	PTF	NON PTF	NON PTF	COMMON	PTF XFR	NPTF XFR
Source RSI numbers prior yrs'			1	2,051,470	2,051,470	2,051,470				
WO 26265	3/10/2010	1280 PTF & 115KV Relay Protec	2	403,563	403,563	403,563				
WO 26093	1/28/2009 *	Install Substation Batteries	3	30,922	30,922	8,470	22,452			
			4							
			5							
			6							
			7				May 18, 2011			
			8							
			9							
			10							
			11							
			12							
			13							
				-	0					
				-	0					
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Regional Network Service
Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO New England Inc. Open Access Transmission Tariff

Shading denotes an input

Submitted on:	May 14, 2012
Revenue Requirements for (year):	Year 2011
Customer:	Norwich Public Utilities
Customer's NABs Number:	8
Name of Participant responsible for customer's billing:	CMEEC
DUNs number of Participant responsible for customer's billing:	09-207-8351

	Pre-97 Revenue Requirements	Post-96 Revenue Requirements
Total of Attachment F - Sections A through I =	169,642 (a)	0 (f)
Total of Attachment F - Section J - Support Revenue	0 (b)	0 (g)
Total of Attachment F - Section K - Support Expense	0 (c)	0 (h)
Total of Attachment F - Section (L through O)	0 (d)	0 (i)
Sub Total - Sum (A through I) - J + K + (L through O)	169,642 (e)=(a)-(b)+(c)+(d)	0 (j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	0	- (k)
Annual True-up (per Attachment C to Attachment F Implementation Rule)	68,463	(m)
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:	238,105 (n)	0 (o) = (e)+ (j) + (k) + ((m)
Total of Attachment F - Section J - Pre-97 Support Revenue (from above)		238,105 (b)
Total of Attachment F - Section J - Post-96 Support Revenue (from above-)		0 (g)
Total of Attachment F - Section K - Post-96 Support Expense (from above)		0 (h)
Voting Share Total for Participant's R Value: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)		<u>238,105</u> (l)=(k)+(b)+(g)-(h)

Shading denotes an input

		Attachment F		
		Reference	NPU	Reference
Line No.	I. INVESTMENT BASE	Section:		
1	Transmission Plant	(A)(1)(a)	\$579,153	Worksheet 3, Line 1
2	General Plant	(A)(1)(b)	\$83,626	Worksheet 3, Line 2
3	Plant Held For Future Use	(A)(1)(c)	\$0	Worksheet 3, Line 4
4	Total Plant (Lines 1 + 2 + 3)		\$662,779	
5	Accumulated Depreciation	(A)(1)(d)	\$531,068	Worksheet 3, Line 7
6	Accumulated Deferred Income Taxes	(A)(1)(e)	\$0	Worksheet 3, Line 10
7	Loss On Reacquired Debt	(A)(1)(f)	\$0	Worksheet 3, Line 11
8	Other Regulatory Assets	(A)(1)(g)	\$0	Worksheet 3, Line 15
9	Net Investment (Line 4 - 5 - 6 + 7 + 8)		\$131,711	
10	Prepayments	(A)(1)(h)	\$1,637	Worksheet 3, Line 16
11	Materials & Supplies	(A)(1)(i)	\$6,223	Worksheet 3, Line 17
12	Cash Working Capital	(A)(1)(j)	\$14,260	Worksheet 3, Line 24
13	Total Investment Base (Line 9 + 10 + 11 + 12)		\$153,831	
II.	REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	\$12,307	Worksheet 2
15	Depreciation Expense	(B)	\$22,205	Worksheet 4, Line 3
16	Amortization of Loss on Reacquired Debt	(C)	\$0	Worksheet 4, Line 4
17	Investment Tax Credit	(D)	\$0	Worksheet 4, Line 5
18	Property Tax Expense	(E)	\$18,888	Worksheet 4, Line 8
19	Payroll Tax Expense	(F)	\$2,160	Worksheet 4, Line 23
20	Operation & Maintenance Expense	(G)	\$12,809	Worksheet 4, Line 13
21	Administrative & General Expense	(H)	\$101,273	Worksheet 4, Line 22
22	Transmission Related Integrated Facilities Charge	(I)	\$0	Worksheet 7
23	Transmission Support Revenue	(J)	\$0	Worksheet 7
24	Transmission Support Expense	(K)	\$0	Worksheet 7
25	Transmission Related Expense from Generators	(L)	\$0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	\$0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	\$0	
28	Transmission Rents Received from Electric Property	(O)	\$0	
29	Total Revenue Requirements (Line 14 thru 28)		\$169,642	

Norwich Public Utilities
Annual Revenue Requirements
for costs in 2011

PTF Revenue Requirements

Worksheet 2 of 7

Shading denotes an input

	CAPITALIZATION 12/31/2011		CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 0	Per 2002 NEPOOL Interpretive Guidance Document (part of Muni RNS audit total investment return should = 8%) DPUC Rpt. P. 201, line 10	0.00%	4.00%	0.00%	0.00%
PREFERRED STOCK			0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	26,940,036		100.00%	8.00%	8.00%	8.00%
TOTAL INVESTMENT RETURN	\$ 26,940,036		100.00%		8.00%	8.00%

	(PTF)	
INVESTMENT BASE	\$ 153,831	From Worksheet 1
x Cost of Capital Rate	8.00%	
= Investment Return and Income Taxes	12,307	To Worksheet 1

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Reference
	<u>Transmission Plant</u>					
1	Transmission Plant		5,233,897		579,153	DPUC Annual Rpt. p. 500
2	General Plant	5.2714% (a)	755,744	11.0654%	83,626	DPUC Annual Rpt. p. 501
3	Total (line 1 + 2)		<u>5,989,641</u>		<u>662,779</u>	
4	<u>Transmission Plant Held for Future Use</u>		0	11.0654%	<u>0</u>	information not available
	<u>Transmission Accumulated Depreciation</u>					
5	Transmission Accum. Depreciation		4,374,074	11.0654%	484,009	DPUC Annual Rpt. p. 508, line 31
6	General Plant Accum. Depreciation	5.2714% (a)	425,284	11.0654%	47,059	DPUC Annual Rpt. p. 508, line 31
7	Total (line 5 + 6)		<u>4,799,358</u>		<u>531,068</u>	
	<u>Transmission Accumulated Deferred Taxes</u>					
8	Accumulated Deferred Taxes	10.4447% (c)	0	11.0654%	0	Not applicable.
9	Accumulated Deferred Taxes	10.4447% (c)	0	11.0654%	0	Not applicable.
10	Total (line 8 + 9)		<u>0</u>		<u>0</u>	
11	<u>Transmission loss on Reacquired Debt</u>	10.4447% (c)	0	11.0654%	<u>0</u>	Not applicable.
	<u>Other Regulatory Assets</u>					
12	FAS 106	5.2714% (a)	0	11.0654%	0	Not applicable.
13	FAS 109	10.4447% (c)	0	11.0654%	0	Not applicable.
14	Other Regulatory Liabilities (254.DK)	10.4447% (c)	0	11.0654%	0	Not applicable.
15	Total (line 12 + 13 + 14)		<u>0</u>		<u>0</u>	
16	<u>Transmission Prepayments</u>	5.2714% (a)	14,792	11.0654%	<u>1,637</u>	DPUC Annual Rpt, p. 210, line 14
17	<u>Transmission Materials and Supplies</u>	10.4447%	<u>56,240</u>	11.0654%	<u>6,223</u>	DPUC Report page 200 Line 25
18	<u>Cash Working Capital</u>					
19	Operation & Maintenance Expense				12,809	Worksheet 4, Line 13
20	Administrative & General Expense				101,273	Worksheet 4, Line 22
21	Transmission Support Expense				0	Worksheet 1, Line 24
22	Subtotal (line 19 + 20 + 21)				<u>114,082</u>	
23					<u>0.125</u>	x 45 days / 360
24	Total (line 22 * line 23)				<u>14,260</u>	

Shading denotes an input		(1)	(2)	(3)	(4)	(5)	
Line No.		(1) Total	Wage/Plant Allocation Factors	= (1)*(2) Transmission Allocated	PTF Allocation Factor (b)	= (3)*(4) PTF Allocated	Reference
<u>Depreciation Expense</u>							
1	Transmission Depreciation	134,098		134,098	11.0654%	14,838	
2	General Depreciation	1,262,982	5.2714% (a)	66,577	11.0654%	7,367	DPUC Annual Rpt. p. 508, line 3
3	Total (line 1+2)			200,675		22,205	
<u>Amortization of Loss on Reacquired Debt</u>							
4		0	10.4447% (c)	0	11.0654%	0	not applicable
<u>Amortization of Investment Tax Credits</u>							
5		0	10.4447% (c)	0	11.0654%	0	not applicable
<u>Property Taxes *</u>							
6	Transmission Property Taxes	150,893		150,893	11.0654%	16,697	See Below
7	General Property Taxes	375,606	5.2714% (a)	19,800	11.0654%	2,191	See Below
8	Total (line 6+7)			170,693		18,888	
<u>Transmission Operation and Maintenance</u>							
9	Operation and Maintenance	151,610		151,610	11.0654%	16,776	DPUC Annual Rpt. P. 518, less 50% of
10	Transmission of Electricity by Others - #565	0		0	11.0654%	0	Information not available.
11	Load Dispatching - #561	211		211	11.0654%	23	DPUC Annual Rpt. P. 518, line 31
12	**Station Expenses & Rents - #562 / #567	35,646		35,646	11.0654%	3,944	DPUC Annual Rpt. P. 518, line 32 & 37
13	O&M less lines 10, 11 & 12	115,753		151,399	11.0654%	12,809	
<u>Transmission Administrative and General</u>							
14	Administrative and General	17,219,143					DPUC Annual Rpt. P. 520, line 18
15	less Property Insurance (#924)	145,534					DPUC Annual Rpt. P. 520, line 7
16	less Regulatory Commission Expenses (#928)	0					Not applicable.
17	less General Advertising Expense (#930.1)	0					Not applicable.
18	Subtotal [line 14 minus (15 thru 17)]	17,073,609	5.2714% (a)	900,018	11.0654%	99,591	
19	PLUS Property Insurance alloc. using Plant Allocator	145,534	10.4447% (c)	15,201	11.0654%	1,682	
20	PLUS Regulatory Comm. Exp. (FERC Assessments)	0	10.4447% (c)	0	11.0654%	0	Not applicable.
21	PLUS Trans. Related General Advertising Expense	0	10.4447% (c)	0	11.0654%	0	Not applicable.
22	Total A&G [line 18 plus (19 thru 21)]	17,219,143		915,219		101,273	
<u>Payroll Tax Expense</u>							
	Federal Unemployment	0	5.2714% (a)	0	11.0654%	0	information not available
	FICA	370,288	5.2714% (a)	19,519	11.0654%	2,160	
	Medicare	0	5.2714% (a)	0	11.0654%	0	information not available
	CT Unemployment	0	5.2714% (a)	0	11.0654%	0	information not available
23		370,288	5.2714% (a)	19,519	11.0654%	2,160	
(a) Worksheet 5 of 8, line 11							
(b) Worksheet 5 of 8, line 3							
(c) Worksheet 5 of 8, line 16							
** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments.							
<u>Total Plant in Service as of 12/31/2010</u>							
	Less Furniture & Fixtures	1,308,393					DPUC Annual Rpt. P. 501, line 18
	Net Taxable Plant	13,028,300					DPUC Annual Rpt. P. 501, line 4
	Applicable Mill Rate	28.83					From Town budget fy11-12
		375,606					Place in cell d6 above.
<u>Transmission Plant in Service as of 12/31/2010</u>							
		5,233,897					

Shading denotes an input

Line

No.

PTF Transmission Plant Allocation Factor		NPU	Reference
1	PTF Transmission Investment	\$579,153	Auditor's tab
2	Total Transmission Investment	\$5,233,897	DPUC Annual Rpt. P. 500
3	Percent Allocation (Line 1/Line 2)	11.0654%	
Transmission Wages and Salaries Allocation Factor			
4	Direct Transmission Wages and Salaries	\$91,450	DPUC Annual Rpt. P. 507, line 4 Worksheet 6
5	Affiliated Company Transmission Wages and Salaries	\$0	
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	\$91,450	
7	Total Wages and Salaries	\$5,600,643	DPUC Annual Rpt. P. 507, line 45
8	Administrative and General Wages and Salaries	\$3,865,809	DPUC Annual Rpt. P. 507, line 9
9	Affiliated Company Wages and Salaries less A&G	\$0	Worksheet 6
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	\$1,734,834	
11	Percent Allocation (Line 6/Line 10)	5.2714%	
Plant Allocation Factor			
12	Total Transmission Investment	\$5,233,897	DPUC Annual Rpt. P. 500 Worksheet 3, Line 2
13	plus Transmission-Related General Plant	\$755,744	
14	= Revised Numerator (Line 12 + Line 13)	\$5,989,641	
15	Total Plant in Service	\$57,346,103	DPUC Annual Rpt. P. 501
16	Percent Allocation (Line 14 / Line 15)	10.4447%	

Affiliated Company Wages and Salaries

Shading denotes an input

Line		NPU
"Affiliated" Transmission Wages and Salaries #560 - 573		
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11 = 1 thru 10	Total Transmission	0
12 = Total "Affiliated" Wages and Salaries		
Less "Affiliated" Administrative and General Salaries #920 - 935		
13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
21 = 13 thru 20		0
22 = 12 less 21	Total "Affiliated" less A&G	0

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	FERC Form 1	TOTAL	
			Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	332.(g); [332.1(g) for HWP]		0
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			0
	Comerford 115 kV Substation			
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	332.1(g); [332(g) for CL&P]		0
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 394 line	332(g)		
	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			0
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310 line	330.1(n)		0
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
Total =			0	0

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

Norwich Public Utilities

FERC Interest Calculation associated with Under / (Over)

True Up and Interest Calculation for RR based on 2010 costs, submitted May 2011

Line	Annual True-up	Pre 1997	Post 1996	Total	
1	Transmission Revenue Requirements (as billed)	103,394		\$ 103,394	ATRR - Prior Year
2	True-up 2010 Actual Annual RR	169,642		\$ 169,642	PTF Pre & Post on ATRR
3	True-up Surcharge / (Refund) (Line 2 - 1)	66,248	-	\$ 66,248	

	Surcharge / (Refund)
Pre 1997	\$ 66,248
Post 1996	\$ -

Initial Billing	Balance		FERC Monthly Interest	Interest	
Period	Pre 1997	Post 1996	Rate	Pre 1997	Post 1996
June 2011	\$ 66,248	\$ -	0.27%	\$ 179	\$ -
July 2011	\$ 66,427	\$ -	0.27%	\$ 179	\$ -
August 2011	\$ 66,427	\$ -	0.28%	\$ 186	\$ -
September 2011	\$ 66,427	\$ -	0.27%	\$ 179	\$ -
October 2011	\$ 66,971	\$ -	0.28%	\$ 188	\$ -
November 2011	\$ 66,971	\$ -	0.27%	\$ 181	\$ -
December 2011	\$ 66,971	\$ -	0.28%	\$ 188	\$ -
January 2012	\$ 67,528	\$ -	0.28%	\$ 189	\$ -
February 2012	\$ 67,528	\$ -	0.27%	\$ 182	\$ -
March 2012	\$ 67,528	\$ -	0.28%	\$ 189	\$ -
April 2012	\$ 68,088	\$ -	0.27%	\$ 184	\$ -
May 2012	\$ 68,088	\$ -	0.28%	\$ 191	\$ -
Total Surcharge/ (Refund)				\$ 68,463	\$ -

	Interest	Principal	Total
Pre 1997	\$ 2,215	\$ 66,248	\$ 68,463
Post 1996	\$ -	\$ -	\$ -
	\$ 2,215	\$ 66,248	\$ 68,463

	NORWICH PUBLIC UTILITIES							
	BEAN HILL SUB	TRANSMISSION			DISTRIBUTION			
	TOTAL	TOTAL	PTF	NON PTF	NON PTF	COMMON	PTF XFR	NPTF XFR
1	15,806	0			15806			
2	430,118	0			430,118			
3	10,751	0			10,751			
4	91,499	91,499		91,499				
5	130,000	130,000	130,000					
6	865,103	0			642,848			222,255
7	36,527	36,527	36,527					
8	112,104	112,104	112,104					
9	-	0				-		
10	6,191	0				6,191		
11	78,030	78,030	78,030					
12	7,640	0				7,640		
13	64,572	0				64,572		
**14	197,593	197,593	197,593					
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
Total	2,045,935		554,254	91,499	1,099,523	78,403	-	222,255
Allocated Common			24,899	4,110	49,394			
Transformers					222,255			
Total	2,045,935	674,763	579,153	95,610	1,371,172			

Regional Network Service
Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO New England Inc. Open Access Transmission Tariff

Shading denotes an input

Submitted on:	<u>May 14, 2012</u>
Revenue Requirements based on Year Ending:	<u>June 30, 2011</u>
Rate Effective for the period:	<u>June 1, 2012</u>
Through:	<u>May 31, 2013</u>
Customer:	<u>Town of Wallingford, Electric Division</u>
Customer's NABs Number:	<u>8</u>
Name of Participant responsible for customer's billing:	<u>CMEEC</u>
DUNS number of Participant responsible for customer's billing:	<u>09-207-8351</u>

	<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>
Total of Attachment F - Sections A through I =	96,820 (a)	<u>590,788 (f)</u>
Total of Attachment F - Section J - Support Revenue	<u>0 (b)</u>	<u>0 (g)</u>
Total of Attachment F - Section K - Support Expense	<u>0 (c)</u>	<u>0 (h)</u>
Total of Attachment F - Section (L through O)	<u>0 (d)</u>	<u>0 (i)</u>
Sub Total - Sum (A through I) - J + K + (L through O)	<u>96,820 (e)=(a)-(b)+(c)+(d)</u>	<u>590,788 (j)</u>

Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements
and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:

687,608 (k) = (e) + (j)

Total of Attachment F - Section J - Pre-97 Support Revenue (from above)	<u>0 (b)</u>
Total of Attachment F - Section J - Post-96 Support Revenue (from above-)	<u>0 (g)</u>
Total of Attachment F - Section K - Post-96 Support Expense (from above)	<u>0 (h)</u>

Voting Share Total for Participant's R Value: 687,608 (l)=(k)+(b)+(g)-(h)
(for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)

Shading denotes an input

		Attachment F		
		Reference	WALLINGFORD	Reference
Line No.	I. INVESTMENT BASE	Section:		
1	Transmission Plant	(A)(1)(a)	\$6,282,177	Worksheet 3, Line 1
2	General Plant	(A)(1)(b)	\$79,017	Worksheet 3, Line 2
3	Plant Held For Future Use	(A)(1)(c)	\$0	Worksheet 3, Line 4
4	Total Plant (Lines 1 + 2 + 3)		\$6,361,194	
5	Accumulated Depreciation	(A)(1)(d)	\$2,813,911	Worksheet 3, Line 7
6	Accumulated Deferred Income Taxes	(A)(1)(e)	\$0	Worksheet 3, Line 10
7	Loss On Reacquired Debt	(A)(1)(f)	\$0	Worksheet 3, Line 11
8	Other Regulatory Assets	(A)(1)(g)	\$0	Worksheet 3, Line 15
9	Net Investment (Line 4 - 5 - 6 + 7 + 8)		\$3,547,283	
10	Prepayments	(A)(1)(h)	\$0	Worksheet 3, Line 16
11	Materials & Supplies	(A)(1)(i)	\$52,054	Worksheet 3, Line 17
12	Cash Working Capital	(A)(1)(j)	\$7,876	Worksheet 3, Line 24
13	Total Investment Base (Line 9 + 10 + 11 + 12)		\$3,607,213	
II.	REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	\$288,577	Worksheet 2
15	Depreciation Expense	(B)	\$176,233	Worksheet 4, Line 3
16	Amortization of Loss on Reacquired Debt	(C)	\$0	Worksheet 4, Line 4
17	Investment Tax Credit	(D)	\$0	Worksheet 4, Line 5
18	Property Tax Expense	(E)	\$159,791	Worksheet 4, Line 8
19	Payroll Tax Expense	(F)	\$0	Worksheet 4, Line 23
20	Operation & Maintenance Expense	(G)	\$33,152	Worksheet 4, Line 13
21	Administrative & General Expense	(H)	\$29,855	Worksheet 4, Line 22
22	Transmission Related Integrated Facilities Charge	(I)	\$0	Worksheet 7
23	Transmission Support Revenue	(J)	\$0	Worksheet 7
24	Transmission Support Expense	(K)	\$0	Worksheet 7
25	Transmission Related Expense from Generators	(L)	\$0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	\$0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	\$0	
28	Transmission Rents Received from Electric Property	(O)	\$0	
29	Total Revenue Requirements (Line 14 thru 28)		\$687,608	

Town of Wallingford, Electric Division
Annual Revenue Requirements
for costs in 2007

PTF Revenue Requirements

Worksheet 2 of 7

Shading denotes an input

	CAPITALIZATION 12/31/2010		CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 0	Per 2002 NEPOOL Interpretive Guidance Document (part of Muni RNS audit total investment return should = 8%) DPUC Rpt. P. 201, line 10	0.00%	6.00%	0.00%	0.00%
PREFERRED STOCK	0		0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	58,355,659		100.00%	8.00%	8.00%	8.00%
TOTAL INVESTMENT RETURN	\$ 58,355,659		100.00%		8.00%	8.00%

	(PTF)	
INVESTMENT BASE	\$ 3,607,213	From Worksheet 1
x Cost of Capital Rate	8.00%	
= Investment Return and Income Taxes	288,577	To Worksheet 1

Town of Wallingford, Electric Division

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Reference
	<u>Transmission Plant</u>					
1	Transmission Plant		9,091,811	69.0971%	6,282,177	DPUC Annual Rpt. p. 501, line 2:
2	General Plant		114,357	69.0971%	79,017	DPUC Annual Rpt. p. 502, line 1:
3	Total (line 1 + 2)		<u>9,206,168</u>		<u>6,361,194</u>	
4	<u>Transmission Plant Held for Future Use</u>		0	69.0971%	<u>0</u>	
	<u>Transmission Accumulated Depreciation</u>					
5	Transmission Accum. Depreciation	3,807,538	3,807,538	69.0971%	2,757,602	Depreciation tab
6	General Plant Accum. Depreciation	6,855,099	81,493	69.0971%	56,309	Depreciation tab
7	Total (line 5 + 6)		<u>3,889,031</u>		<u>2,813,911</u>	
	<u>Transmission Accumulated Deferred Taxes</u>					
8	Accumulated Deferred Taxes	0	0	69.0971%	0	not applicable
9	Accumulated Deferred Taxes	0	0	69.0971%	0	not applicable
10	Total (line 8 + 9)		<u>0</u>		<u>0</u>	
11	<u>Transmission loss on Reacquired Debt</u>	0	0	69.0971%	<u>0</u>	not applicable
	<u>Other Regulatory Assets</u>					
12	FAS 106	0	0	69.0971%	0	not applicable
13	FAS 109	0	0	69.0971%	0	not applicable
14	Other Regulatory Liabilities (254.DK)	0	0	69.0971%	0	not applicable
15	Total (line 12 + 13 + 14)	<u>0</u>	<u>0</u>		<u>0</u>	
16	<u>Transmission Prepayments</u>	0	0	69.0971%	<u>0</u>	Assumed none
17	<u>Transmission Materials and Supplies</u>	814,788	75,334	69.0971%	<u>52,054</u>	DPUC Report page 200 Line 25
18	<u>Cash Working Capital</u>					
19	Operation & Maintenance Expense				33,152	Worksheet 4, Line 13
20	Administrative & General Expense				29,855	Worksheet 4, Line 22
21	Transmission Support Expense				0	Worksheet 1, Line 24
22	Subtotal (line 19 + 20 + 21)				<u>63,007</u>	
23					<u>0.125</u>	x 45 days / 360
24	Total (line 22 * line 23)				<u>7,876</u>	

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Reference
<u>Depreciation Expense</u>						
1	251,287		251,287	69.0971%	173,632	25 Year Depreciation
2	316,601	1.1888% (a)	3,764	69.0971%	2,601	see below
3			255,051		176,233	
4	0	9.2458% (c)	0	69.0971%	0	not applicable
5	0	9.2458% (c)	0	69.0971%	0	not applicable
<u>Property Taxes *</u>						
6	229,295		229,295	69.0971%	158,437	See Below
7	164,832	1.1888% (a)	1,960	69.0971%	1,354	information not available
8			231,255		159,791	
<u>Transmission Operation and Maintenance</u>						
9	47,979		47,979	69.0971%	33,152	DPUC Annual Rpt. p. 518, line 47
10	0		0	69.0971%	0	information not available
11	0		0	69.0971%	0	information not available
12	0		0	69.0971%	0	information not available
13	47,979		47,979	69.0971%	33,152	
<u>Transmission Administrative and General</u>						
14	3,358,816					DPUC Annual Rpt. p. 520, line 18
15	40,689					DPUC Annual Rpt. p. 520, line 7
16	0					not applicable
17	0					not applicable
18	3,318,127	1.1888% (a)	39,446	69.0971%	27,256	
19	40,689	9.2458% (c)	3,762	69.0971%	2,599	
20	0	9.2458% (c)	0	69.0971%	0	not applicable
21	0	9.2458% (c)	0	69.0971%	0	not applicable
22	3,358,816		43,208		29,855	
<u>Payroll Tax Expense</u>						
	0	1.1888% (a)	0	69.0971%	0	information not available
	0	1.1888% (a)	0	69.0971%	0	information not available
	0	1.1888% (a)	0	69.0971%	0	information not available
	0	1.1888% (a)	0	69.0971%	0	information not available
23	0	1.1888% (a)	0	69.0971%	0	

(a) Worksheet 5 of 8, line 11, Transmission Wages & Salary Allocator
(b) Worksheet 5 of 8, line 3, PTF Transmission Plant allocator
(c) Worksheet 5 of 8, line 16, Plant Allocator

** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments.

Total Plant in Service as of 6/30/11	9,619,518	
Less Furniture & Fixtures	3,083,768	DPUC Report Page 502 Line4
Net Taxable Plant	6,535,750	
Applicable Mil Rate	25.22	
	164,832	To cell d7 above

general depreciation = Total Depr DPUC pg 508 L 3 x (total general plant DPUC pg 502 L12 / total plant in service wksh 5)

Shading denotes an input

Line
No.

PTF Transmission Plant Allocation Factor		WALLINGFORD	Reference
1	PTF Transmission Investment	\$6,282,177	Auditor's tabs
2	Total Transmission Investment	\$9,091,811	DPUC Page 501 line22
3	Percent Allocation (Line 1/Line 2)	69.0971%	
Transmission Wages and Salaries Allocation Factor			
4	Direct Transmission Wages and Salaries	\$40,092	DPUC Annual Rpt. P. 507, line 22 Worksheet 6
5	Affiliated Company Transmission Wages and Salaries	\$0	
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	\$40,092	
7	Total Wages and Salaries	\$3,973,872	DPUC Annual Rpt. P. 507, line 44 DPUC Annual Rpt. P. 507, line 9 Worksheet 6
8	Administrative and General Wages and Salaries	\$601,261	
9	Affiliated Company Wages and Salaries less A&G	\$0	
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	\$3,372,611	
11	Percent Allocation (Line 6/Line 10)	1.1888%	
Plant Allocation Factor			
12	Total Transmission Investment	\$9,091,811	DPUC Page 501 line22 Worksheet 3, Line 2, Col 3
13	plus Transmission-Related General Plant	\$114,357	
14	= Revised Numerator (Line 12 + Line 13)	\$9,206,168	
15	Total Plant in Service	\$99,571,509	DPUC Annual Rpt. P. 502, line 18
16	Percent Allocation (Line 14 / Line 15)	9.2458%	

Affiliated Company Wages and Salaries

Shading denotes an input

Line		WALLINGFORD
"Affiliated" Transmission Wages and Salaries #560 - 573		
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11 = 1 thru 10	Total Transmission	0
12 = Total "Affiliated" Wages and Salaries		
Less "Affiliated" Administrative and General Salaries #920 - 935		
13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
21 = 13 thru 20		0
22 = 12 less 21	Total "Affiliated" less A&G	0

Town of Wallingford, Electric Division

PTF Revenue Requirements
Worksheet 7 of 7

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	FERC Form 1	TOTAL	
			Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	332.(g); [332.1(g) for HWP]		0
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			0
	Comerford 115 kV Substation			
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	332.1(g); [332(g) for CL&P]		0
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 394 line	332(g)		
	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			0
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310 line	330.1(n)		0
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
Total =			0	0

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

TOWN OF WALLINGFORD

COLONY SUB	TRANSMISSION			DISTRIBUTION	COMMON	PTF XFR	NPTF XFR
	TOTAL	PTF	NON PTF				
602,612					602,612		
65,602					65,602		
332,061					332,061		
165,000					165,000		
19,727					19,727		
39,387					39,387		-
60,800			60,800				
52,400		34,933	17,467				
8,347			8,347				
71,500		71,500					
23,010		23,010					
304,170				304,170			
80,600					80,600		
7,965					7,965		
1,200					1,200		
42,002		28,001	14,001				
151,842					151,842		
27,488							27,488
4,001					4,001		
1,640					1,640		
51,568		34,379	17,189				
24,978					24,978		
1,850					1,850		
556,942					556,942		
185,800				185,800			
150,862					150,862		
217					217		
4,199					4,199		
1,580					1,580		
1,418					1,418		
3,585					3,585		
Total	3,044,353	191,823	117,804	489,970	2,217,268	-	27,488
Allocated Common Transformers		531,923	326,667	1,358,678			
Total	3,044,353	1,168,217	723,746	1,876,136			

N. WALLINGFORD	TRANSMISSION			DISTRIBUTION	COMMON	PTF XFR	NPTF XFR
	TOTAL	PTF	NON PTF				
120,000		80,000	40,000				
1,122		748	374				
1,024,196					617,363		406,833
136,000					136,000		
2,332					2,332		
2,332					2,332		
3,278					3,278		
29,610					29,610		
900			900				
2,062					2,062		
9,462					9,462		
350					350		
663,545				663,545			
32,865					32,865		
Total	2,028,054	80,748	41,274	663,545	835,654	-	406,833
Allocated Common Transformers		85,896	43,906	705,852			
Total	2,028,054	251,824	166,644	1,776,230			
Total Redistribution	5,072,407	1,420,041	890,390	3,652,366	-	-	-
Other Trans. Plant	1,280,640		1,280,640				
Total Wallingford	6,353,047	890,390	1,810,291	3,652,366			
	6,353,047	2,700,681					
		0.425100124	14.02%	57.49%			
			2,700,681				

<i>Newly Installed 2007</i>				
Description	Quantity	Units	Price/Unit	Total Cost
3-1/2" NPS Aluminum Bus	372	ft.	\$ 15.00	\$ 5,580.00
Horizontal Bus Supports	2	ea.	\$ 10,000.00	\$ 20,000.00
Corner Bus Support	1	ea.	\$ 13,000.00	\$ 13,000.00
115kV Switch Support Stand	2	ea.	\$ 15,000.00	\$ 30,000.00
115kV Disconnect Switch (13M-6T-2)	1	ea.	\$ 9,700.00	\$ 9,700.00
115kV Disconnect Switch (13M-6T-8)	1	ea.	\$ 9,700.00	\$ 9,700.00
115 kV Circuit Breaker Footings & other foundations	1	ea.	\$ 80,000.00	\$ 80,000.00
115kV SF6 Circuit Breaker	1	ea.	\$ 62,000.00	\$ 62,000.00
Breaker Relay Panel 6P	1	ea.	\$ 28,400.00	\$ 28,400.00
Breaker Control Panel 8R/8C	1	ea.	\$ 66,200.00	\$ 66,200.00
115kV MOD (13M-6T-5) with ground switch	1	ea.	\$ 14,500.00	\$ 14,500.00
115kV MOD Switch Support Stand	1	ea.	\$ 17,000.00	\$ 17,000.00
Insulators *	12	ea.	\$ 1,100.00	\$ 13,200.00
Lightning Arrestors	3	ea.	\$ 2,200.00	\$ 6,600.00
CCVT (1507-13M-1H)	3	ea.	\$ 6,815.00	\$ 20,445.00

Added to report @ 2007

\$ 396,325.00

Regional Network Service
Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO New England Inc. Open Access Transmission Tariff

Shading denotes an input

Submitted on:	<u>May 14, 2012</u>
Revenue Requirements for (year):	<u>Year 2011</u>
Rate Effective for the period:	<u>June 1, 2012</u>
Through:	<u>May 31, 2013</u>
Customer:	<u>Mohegan Tribal Utility Authority</u>
Customer's NABs Number:	<u>8</u>
Name of Participant responsible for customer's billing:	<u>CMEEC</u>
DUNs number of Participant responsible for customer's billing:	<u>09-207-8351</u>

	<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>
Total of Attachment F - Sections A through I =	<u>0</u> (a)	<u>\$ 311,984</u> (f)
Total of Attachment F - Section J - Support Revenue	<u>0</u> (b)	<u>0</u> (g)
Total of Attachment F - Section K - Support Expense	<u>0</u> (c)	<u>0</u> (h)
Total of Attachment F - Section (L through O)	<u>0</u> (d)	<u>0</u> (i)
Sub Total - Sum (A through I) - J + K + (L through O)	<u>0</u> (e)=(a)-(b)+(c)+(d)	<u>\$ 311,984</u> (j)
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:		<u>\$ 311,984</u> (k) = (e) + (j)
Total of Attachment F - Section J - Pre-97 Support Revenue (from above)		<u>0</u> (b)
Total of Attachment F - Section J - Post-96 Support Revenue (from above-)		<u>0</u> (g)
Total of Attachment F - Section K - Post-96 Support Expense (from above)		<u>0</u> (h)
Voting Share Total for Participant's R Value: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)		<u>\$ 311,984</u> (l)=(k)+(b)+(g)-(h)

Shading denotes an input

		Attachment F		
		Reference	MTUA	Reference
Line No.	I. INVESTMENT BASE	Section:		
1	Transmission Plant	(A)(1)(a)	\$2,694,352	Worksheet 3, Line 1
2	General Plant	(A)(1)(b)	\$0	Worksheet 3, Line 2
3	Plant Held For Future Use	(A)(1)(c)	\$0	Worksheet 3, Line 4
4	Total Plant (Lines 1 + 2 + 3)		\$2,694,352	
5	Accumulated Depreciation	(A)(1)(d)	\$1,077,741	Worksheet 3, Line 7
6	Accumulated Deferred Income Taxes	(A)(1)(e)	\$0	Worksheet 3, Line 10
7	Loss On Reacquired Debt	(A)(1)(f)	\$0	Worksheet 3, Line 11
8	Other Regulatory Assets	(A)(1)(g)	\$0	Worksheet 3, Line 15
9	Net Investment (Line 4 - 5 - 6 + 7 + 8)		\$1,616,611	
10	Prepayments	(A)(1)(h)	\$0	Worksheet 3, Line 16
11	Materials & Supplies	(A)(1)(i)	\$0	Worksheet 3, Line 17
12	Cash Working Capital	(A)(1)(j)	\$1,598	Worksheet 3, Line 24
13	Total Investment Base (Line 9 + 10 + 11 + 12)		\$1,618,209	
II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	\$129,457	Worksheet 2
15	Depreciation Expense	(B)	\$107,774	Worksheet 4, Line 3
16	Amortization of Loss on Reacquired Debt	(C)	\$0	Worksheet 4, Line 4
17	Investment Tax Credit	(D)	\$0	Worksheet 4, Line 5
18	Property Tax Expense	(E)	\$61,970	Worksheet 4, Line 8
19	Payroll Tax Expense	(F)	\$0	Worksheet 4, Line 23
20	Operation & Maintenance Expense	(G)	\$12,783	Worksheet 4, Line 13
21	Administrative & General Expense	(H)	\$0	Worksheet 4, Line 22
22	Transmission Related Integrated Facilities Charge	(I)	\$0	Worksheet 7
23	Transmission Support Revenue	(J)	\$0	Worksheet 7
24	Transmission Support Expense	(K)	\$0	Worksheet 7
25	Transmission Related Expense from Generators	(L)	\$0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	\$0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	\$0	
28	Transmission Rents Received from Electric Property	(O)	\$0	
29	Total Revenue Requirements (Line 14 thru 28)		\$311,984	

Mohegan Tribal Utility Authority
Annual Revenue Requirements
for costs in 2010

PTF Revenue Requirements

Worksheet 2 of 7

Shading denotes an input

	CAPITALIZATION <u>12/31/2010</u>		CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 0	Per 2002 NEPOOL Interpretive Guidance Document (part of Muni RNS audit total investment return should = 8%) Historical	0.00%	6.00%	0.00%	0.00%
PREFERRED STOCK	0		0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	<u>6,000,000</u>		<u>100.00%</u>	<u>8.00%</u>	<u>8.00%</u>	<u>8.00%</u>
TOTAL INVESTMENT RETURN	0 <u><u>6,000,000</u></u>		<u><u>100.00%</u></u>		<u><u>8.00%</u></u>	<u><u>8.00%</u></u>

	<u>(PTF)</u>	
INVESTMENT BASE	\$ 1,618,209	From Worksheet 1
x Cost of Capital Rate	8.00%	
= Investment Return and Income Taxes	<u><u>129,457</u></u>	To Worksheet 1

	Shading denotes an input					
		(1)	(2)	(3)	(4)	(5)
			Wage/Plant	= (1)*(2)	PTF	= (3)*(4)
Line			Allocation	Transmission	Allocation	PTF
No.		Total	Factors	Allocated	Factor (b)	Allocated
	<u>Transmission Plant</u>					
1	Transmission Plant	\$ 6,059,395		6,059,395	44.4657%	2,694,352
2	General Plant		100.0000% (a)	0	44.4657%	0
3	Total (line 1 + 2)			6,059,395		2,694,352
4	<u>Transmission Plant Held for Future Use</u>	0		0	44.4657%	0
	<u>Transmission Accumulated Depreciation</u>					
5	Transmission Accum. Depreciation	2,423,758		2,423,758	44.4657%	1,077,741
6	General Plant Accum. Depreciation	0	100.0000% (a)	0	44.4657%	0
7	Total (line 5 + 6)			2,423,758		1,077,741
	<u>Transmission Accumulated Deferred Taxes</u>					
8	Accumulated Deferred Taxes	0	100.0000% (c)	0	44.4657%	0
9	Accumulated Deferred Taxes	0	100.0000% (c)	0	44.4657%	0
10	Total (line 8 + 9)			0		0
11	<u>Transmission loss on Reacquired Debt</u>	0	100.0000% (c)	0	44.4657%	0
	<u>Other Regulatory Assets</u>					
12	FAS 106	0	100.0000% (a)	0	44.4657%	0
13	FAS 109	0	100.0000% (c)	0	44.4657%	0
14	Other Regulatory Liabilities (254.DK)	0	100.0000% (c)	0	44.4657%	0
15	Total (line 12 + 13 + 14)	0		0		0
16	<u>Transmission Prepayments</u>	0	100.0000% (a)	0	44.4657%	0
17	<u>Transmission Materials and Supplies</u>	0	100.0000%	0	44.4657%	0
18	<u>Cash Working Capital</u>					
19	Operation & Maintenance Expense					12,783
20	Administrative & General Expense					0
21	Transmission Support Expense					0
22	Subtotal (line 19 + 20 + 21)					12,783
23						0.125
24	Total (line 22 * line 23)					1,598
						x 45 days / 360

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Reference
<u>Depreciation Expense</u>						
1	242,376		242,376	44.4657%	107,774	25 year depreciation
2	0	100.0000% (a)	0	44.4657%	0	
3			242,376		107,774	
4	0	100.0000% (c)	0	44.4657%	0	not applicable
5	0	100.0000% (c)	0	44.4657%	0	not applicable
<u>Property Taxes *</u>						
6	139,366	100.0000%	139,366	44.4657%	61,970	See Below
7	0	100.0000% (a)	0	44.4657%	0	information not available
8			139,366		61,970	
<u>Transmission Operation and Maintenance</u>						
9	28,749		28,749	44.4657%	12,783	MTUA
10	0		0	44.4657%	0	information not available
11	0		0	44.4657%	0	information not available
12	0		0	44.4657%	0	information not available
13	28,749		28,749	44.4657%	12,783	
<u>Transmission Administrative and General</u>						
14	0					information not available
15	0					information not available
16	0					information not available
17	0					information not available
18	0	100.0000% (a)	0	44.4657%	0	
19	0	100.0000% (c)	0	44.4657%	0	
20	0	100.0000% (c)	0	44.4657%	0	not applicable
21	0	100.0000% (c)	0	44.4657%	0	not applicable
22	0		0		0	
<u>Payroll Tax Expense</u>						
	0	100.0000% (a)	0	44.4657%	0	information not available
	0	100.0000% (a)	0	44.4657%	0	information not available
	0	100.0000% (a)	0	44.4657%	0	information not available
	0	100.0000% (a)	0	44.4657%	0	information not available
23	0	100.0000% (a)	0	44.4657%	0	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments.

Total Plant in Service as of 12/31/2011	6,059,395	
Less Furniture & Fixtures	0	
Net Taxable Plant	6,059,395	
Applicable Mil Rate	23.00	
	139,366	To cell d6 above

Shading denotes an input

Line
No.

PTF Transmission Plant Allocation Factor		MTUA	Reference
1	PTF Transmission Investment	\$2,694,352	See Inventory Tab
2	Total Transmission Investment	\$6,059,395	See Inventory Tab
3	Percent Allocation (Line 1/Line 2)	44.4657%	
Transmission Wages and Salaries Allocation Factor		0	
4	Direct Transmission Wages and Salaries	\$8,876	MTUA Worksheet 6
5	Affiliated Company Transmission Wages and Salaries	\$0	
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	\$8,876	
7	Total Wages and Salaries	\$8,876	Information not available Information not available
8	Administrative and General Wages and Salaries	\$0	
9	Affiliated Company Wages and Salaries less A&G	\$0	
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	\$8,876	
11	Percent Allocation (Line 6/Line 10)	100.0000%	
Plant Allocation Factor			
12	Total Transmission Investment	\$6,059,395	See Inventory Tab Worksheet 3, Line 2
13	plus Transmission-Related General Plant	\$0	
14	= Revised Numerator (Line 12 + Line 13)	\$6,059,395	
15	Total Plant in Service	\$6,059,395	Information not available
16	Percent Allocation (Line 14 / Line 15)	100.0000%	

Affiliated Company Wages and Salaries

Shading denotes an input

Line		MTUA
"Affiliated" Transmission Wages and Salaries #560 - 573		
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11 = 1 thru 10	Total Transmission	0
12 = Total "Affiliated" Wages and Salaries		
Less "Affiliated" Administrative and General Salaries #920 - 935		
13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
21 = 13 thru 20		0
22 = 12 less 21	Total "Affiliated" less A&G	0

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	FERC Form 1	TOTAL	
			Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	332.(g); [332.1(g) for HWP]		0
	345 kV "stabilizer" 342 line		0	
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			0
	Comerford 115 kV Substation			
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	332.1(g); [332(g) for CL&P]		0
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 394 line	332(g)		
	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			0
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310 line	330.1(n)		0
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
Total =			0	0

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

Vendor	Invoice #	Component	Amount	Transmission	Distribution		Common	Comments
					Other	Transformer		
		1.52 Acres of land @ \$10,000/Acre	\$14,348.00	\$3,306.00	\$7,025.00		\$4,017.00	Woronik.
A/Z Corporation	1-02-200	Sitework and Concrete	\$841,000.00	\$193,430.00	\$412,090.00		\$235,480.00	Split based on land use
A/Z Corporation	1-02-801	Filter Fabric	\$8,000.00				\$8,000.00	
A/Z Corporation	1-02-802	Grade Revisions	\$12,544.71				\$12,544.71	
A/Z Corporation	1-02-803	Fill at Access Road	\$4,032.00				\$4,032.00	
A/Z Corporation	1-02-804	One Ince Fence Fabric	\$9,375.00				\$9,375.00	
A/Z Corporation	1-02-805	Dumpster	\$2,768.02				\$2,768.02	
A/Z Corporation	1-02-806	Catch Basin and Stone	\$5,000.00				\$5,000.00	
A/Z Corporation	1-02-807	5000 PSI Concrete	\$850.00	\$255.00	\$340.00		\$255.00	Estimate 30%-T, 40%-D, 30%-C
A/Z Corporation	1-02-808	Security	\$4,030.65				\$4,030.65	
A/Z Corporation	1-02-809	Trees @ Bank	\$4,374.00				\$4,374.00	
A/Z Corporation	1-02-812	Temp Generator	\$7,096.79				\$7,096.79	
A/Z Corporation	1-02-813	Revised Berm	\$2,546.00				\$2,546.00	
A/Z Corporation	1-02-814	Additional Paving	\$7,491.99				\$7,491.99	
A/Z Corporation	1-02-902	Fencing	\$29,000.00	\$7,540.00	\$10,150.00		\$11,310.00	
A/Z Corporation	1-05-801	Welding @ PCR	\$1,457.84	\$437.35	\$728.92		\$291.57	Estimate 30%-T, 50%-D, 20%-C
A/Z Corporation	1-15-801	Plumbing Hook-Up	\$889.00				\$889.00	
A/Z Corporation	1-16-100	Electrical	\$222,833.02	\$66,849.91	\$111,416.51		\$44,566.60	Estimate 30%-T, 50%-D, 20%-C
A/Z Corporation	1-16-200	Component Installation	\$347,998.50	\$208,799.10	\$69,599.70		\$69,599.70	Estimate 60%-T, 20%-D, 20%-C
A/Z Corporation	1-16-400	Cable Installation	\$228,470.00		\$228,470.00			
A/Z Corporation	1-16-801	Ground Cable	\$14,673.88	\$3,374.99	\$7,190.20		\$4,108.69	Split based on land use
A/Z Corporation	1-16-802	Hawkeye Extras	\$30,781.29				\$30,781.29	
A/Z Corporation	1-16-804	Revise Conduits	\$4,410.53				\$4,410.53	
A/Z Corporation	1-16-805	110V & Telephone Circuits	\$4,277.76				\$4,277.76	
A/Z Corporation	1-16-806	Additional VCT's	\$15,793.00				\$15,793.00	
A/Z Corporation	1-16-807	Primary Power	\$33,557.00				\$33,557.00	
A/Z Corporation	1-16-808	Set Generators	\$12,572.00				\$12,572.00	
A/Z Corporation	2-91-205	Construction Management Fee	\$74,232.94				\$74,232.94	
Basler Electric		under/overvoltage relay	\$2,346.00	\$2,346.00				
Camaro Sign	01-1554	Signage	\$264.00	\$84.00	\$180.00			
Camaro Sign	01-1613	Signage	\$990.00				\$990.00	
Camaro Sign		Signage	\$320.00	\$160.00	\$160.00			
Carini & Associates	14	Archaeologist	\$705.80				\$705.80	
CMEEC		NU engineering & construction for 115kv tap	\$355,000.00	\$355,000.00				
CMEEC		NU engineering & construction for 115kv tap	\$300,000.00	\$300,000.00				
CMEEC		NU engineering & construction for 115kv tap	\$450,000.00	\$450,000.00				
CMEEC		NU engineering & construction for 115kv tap	\$250,000.00	\$250,000.00				
CMEEC		NU engineering & construction for 115kv tap	\$65,000.00	\$65,000.00				
Cristino Associates	12334	Electrical design, engineering Siting Council	\$2,390.00				\$2,390.00	
Cristino Associates	12389	Engineering Design	\$6,205.00				\$6,205.00	
Cristino Associates	12410	Engineering Design	\$3,502.50				\$3,502.50	
Cristino Associates	12422	Engineering Design	\$5,350.00				\$5,350.00	
Cristino Associates	12454	Engineering Design	\$22,692.28		\$5,610.00		\$17,082.28	
Cristino Associates	12470	Engineering Design	\$2,420.00				\$2,420.00	
Cristino Associates	12471	Engineering Design	\$7,660.00				\$7,660.00	
Cristino Associates	12498	Engineering Design	\$4,425.00				\$4,425.00	
Cristino Associates	12540	Engineering Design	\$4,460.00				\$4,460.00	
Cristino Associates	12566	Engineering Design	\$14,437.36				\$14,437.36	
Cristino Associates	12608	Engineering Design	\$28,028.17				\$28,028.17	
Cristino Associates	12625	Engineering Design	\$14,155.92				\$14,155.92	
Cristino Associates	12653	Engineering Design	\$21,994.73				\$21,994.73	
Cristino Associates	12688	Engineering Design	\$18,750.00				\$18,750.00	
Cristino Associates	12712	Engineering Design	\$18,919.20				\$18,919.20	
Cristino Associates	12728	Engineering Design	\$21,195.00				\$21,195.00	
Cristino Associates	12782	Engineering Design	\$27,115.00				\$27,115.00	
Cristino Associates	12751	Engineering Design	\$7,728.81	\$7,728.81				
Cristino Associates	12758	Engineering Design	\$36,568.00				\$36,568.00	
Cristino Associates	12768	Engineering Design	\$493.06				\$493.06	
Cristino Associates	12769	Engineering Design	\$29,955.00				\$29,955.00	
Cristino Associates	12796	Engineering Design	\$4,517.70		\$4,517.70			
Cristino Associates	12827	Engineering Design	\$878.00	\$878.00				
Cristino Associates	12834	Engineering Design	\$7,562.50	\$7,562.50				
Cristino Associates	12839	Engineering Design	\$2,365.00		\$2,365.00			
Cristino Associates	12843	Engineering Design	\$3,733.13	\$3,733.13				
Cristino Associates	12848	Engineering Design	\$3,245.00	\$3,245.00				
Cristino Associates	12854	Engineering Design	\$990.00	\$990.00				
Cristino Associates	12862	Engineering Design	\$10,007.40				\$10,007.40	
Cristino Associates	12863	Engineering Design	\$21,934.00	\$21,934.00				
Cristino Associates	12871	Engineering Design	\$1,245.38				\$1,245.38	
Cristino Associates	12908	Engineering Design	\$11,008.14				\$11,008.14	
Cristino Associates	12907	Engineering Design	\$10,350.00				\$10,350.00	
Cristino Associates	12915	Engineering Design	\$838.98	\$838.98				
Cristino Associates	13021	Engineering Design	\$10,627.50				\$10,627.50	
Cristino Associates	13022	Engineering Design	\$8,005.92				\$8,005.92	
Cristino Associates	13023	Engineering Design	\$4,000.00				\$4,000.00	
CT Siting Council	CSC-201-022801	Docket Expenses	\$3,976.90				\$3,976.90	
CT Siting Council	CSC-201-033101	Docket Expenses	\$4,512.69				\$4,512.69	
CT Siting Council	CSC-201-043001	Docket Expenses	\$2,708.18				\$2,708.18	
CT Siting Council	CSC-201-053101	Docket Expenses	\$1,845.59				\$1,845.59	
CT Siting Council	CSC-201-063001	Docket Expenses	\$188.68				\$188.68	
CT Siting Council	CSC-201-73101	Docket Expenses	\$481.04				\$481.04	
Delta Star	116007	1 - 24/32/40MVA Transformer	\$418,640.00			\$418,640.00		
Delta Star	119588	Transformer aux.	\$1,800.00	\$1,800.00				
Delta Star	1794	Move & upgrade 1 - 24MVA Transformer	\$63,669.51	\$19,100.85		\$44,568.66		
Heller, Heller & McCoy	100060	Town P&Z approval	\$330.00				\$330.00	
Heller, Heller & McCoy	100061	Town P&Z approval	\$405.00				\$405.00	
HESCO	381052-01	Miscellaneous wire makers	\$293.82	\$293.82				
Jay's Landscaping		Screening trees required by Siting Council	\$8,956.47				\$8,956.47	
Jerry's Electric	70761	34.5kv to 208/120 station service transformers (two) to power up PCR	\$7,760.00				\$7,760.00	
Lapp Insulator Company	283271	115kV Station Post Insulators	\$4,688.00	\$4,688.00				
Manafort Brothers Inc.	000516-MTUA	Berm work required by Siting Council	\$47,046.00				\$47,046.00	

Vendor	Invoice #	Component	Amount	Transmission	Distribution		Common	Comments
					Other	Transformer		
McFarland-Johnson	4	Site Plan design & engineering	\$46,860.00				\$46,860.00	
McFarland-Johnson	5	Site Plan design & engineering	\$4,570.00				\$4,570.00	
McFarland-Johnson	6	Site Plan design & engineering	\$1,828.00				\$1,828.00	
McFarland-Johnson	7	Site Plan design & engineering	\$2,742.00				\$2,742.00	
Northeast Testing	0049923-IN	Electrical equipment testing	\$27,360.00				\$27,360.00	
Northeast Testing	0050031-IN	Electrical equipment testing	\$15,150.00				\$15,150.00	
Northeast Testing	0050032-IN	Electrical equipment testing	\$15,260.00	\$15,260.00				
Northeast Testing	0050404-IN	Electrical equipment testing	\$9,894.00	\$9,894.00				
Northeast Testing	0050547-IN	Electrical equipment testing	\$4,400.00				\$4,400.00	
Northeast Testing	0050552-IN	Electrical equipment testing	\$24,290.00	\$24,290.00				
Northeast Testing	0050557-IN	Electrical equipment testing	\$16,260.00	\$16,260.00				
Northeast Testing	0050578-IN	Electrical equipment testing	\$17,100.00	\$17,100.00				
Northeast Testing	0050707-IN	Electrical equipment testing	\$21,441.00	\$21,441.00				
Northeast Testing	0050706-IN	Electrical equipment testing	\$19,500.00	\$19,500.00				
Northeast Testing	0050933-IN	Electrical equipment testing	\$3,510.00	\$3,510.00				
Northeast Utilities Service Co.		NU engineering & construction for 115kv tap	\$20,000.00	\$20,000.00				
Pascor	B-SW6042638	MOD's	\$56,699.40	\$43,319.60	\$13,378.80			
PLM	4921	34.5kv Relay settings	\$597.88		\$597.88			
PLM	3659R	115kv Tap Line mods	\$1,142.43	\$1,142.43				
PLM	5103	115kv Relay Settings	\$1,620.92	\$1,620.92				
Powell Electric	H01-0290-516	Power control room	\$1,152,599.00	\$345,779.70	\$576,299.50		\$230,519.80	Estimate 30%-T, 50%-D, 20%-C
S&C Electric	583722	Field Support	\$3,945.08		\$3,945.08			
S&C Electric	709712	Circuit-switchers	\$66,080.00		\$66,080.00			
Schweitzer Engineering	88164	Commissioning support	\$1,766.00	\$1,766.00				
SBC SNET		Phone line installer	\$9,043.00	\$9,043.00				
Southern States	25072	MOD operators	\$17,100.00	\$11,400.00	\$5,700.00			
Trench Limited	37217	1-Line Trap	\$10,300.00	\$10,300.00				
Trench Limited	54153	6-Capacitor voltage transformers	\$21,600.00	\$21,600.00				
Trench Limited	54155	1-Line tuner	\$2,950.00	\$2,950.00				
Valmont	646582	H-frames, steel supports & stands	\$55,044.00	\$49,462.00	\$5,582.00			
Valmont	646701		\$142.24	\$142.24				
WESCO	167910	Miscellaneous material to rewire relays per NU changes	\$6,265.40	\$6,265.40				
WESCO	703742		\$258.00	\$258.00				
WESCO	334448		\$1,505.85				\$1,505.85	
WESCO	355143		\$202.86	\$202.86				
WESCO	306645		\$28.80	\$28.80				
WESCO	318468		\$177.00	\$177.00				
WESCO	330160		\$1,170.00				\$1,170.00	
WESCO	435492		\$642.60				\$642.60	
Wisvest-CT		ABB 115kv breaker	\$60,000.00	\$60,000.00				
Yarde Metals Inc.	1620975	Aluminum bus	\$57.75	\$57.75				
Yarde Metals Inc.	1608166	Aluminum bus	\$155.10	\$155.10				
Yarde Metals Inc.	1607239	Aluminum bus	\$339.90	\$339.90				
Yarde Metals Inc.	1620974	Aluminum bus	\$1,711.05	\$1,711.05				
TOTALS			\$6,059,394.54	\$2,694,352.19	\$1,531,426.29	\$463,208.66	\$1,370,406.40	

Schedule 9

		2006	2007	2008	2009	2010	2011
NE Power HQII	Support Payments/ Revenue Requirements	\$ 62,266.00	\$ 52,880.00	\$ 52,880.00	\$ 55,341.71	\$ 58,133.65	\$ 54,565.55
NSTAR		4,975.19	4,319.58	3,716.53	4,268.42	3,869.15	3,808.00
Chester Facilities		32,692.28	28,518.14	29,733.16	25,879.18	24,191.35	23,172.75

Voting Share
Regional Network Service
Annual Transmission Revenue Requirements
per Tariff Attachment F and ISO New England Inc. OATT

Shading denotes an input

Submitted on:	7-May-12
Revenue Requirements for (year):	2012
Rate Effective for the period:	June 1, 2012
Through:	May 31, 2013
Customer:	CTMEEC
Customer's NABs Number:	
Name of Participant responsible for customer's billing:	CTMEEC
DUNs number of Participant responsible for customer's billing:	96-773-8696

	Pre-97 Revenue Requirements	Post-97 Revenue Requirements
Total of Attachment F - Sections A through I =	0 (a)	6,489,885 (f)
Total of Attachment F - Section J - Support Revenue	0 (b)	0 (g)
Total of Attachment F - Section K - Support Expense	0 (c)	0 (h)
Total of Attachment F - Section (L through O)	0 (d)	0 (i)
Sub Total - Sum (A through I) - J + K + (L through O)	0 (e)=(a)-(b)+(c)+	6,489,885 (j)=(f)-(g)+(h)+(i)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)		1,605,619 (k)
Annual True-up (per Attachment C to Attachment F Implementation Rule)		(918,056) (m)

Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements
and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff: 7,177,448 (o) = (j)+(k)+(m)

Total of Attachment F - Section J - Pre-97 Support Revenue (from above)	<u>0</u> (b)
Total of Attachment F - Section J - Post-96 Support Revenue (from above-)	<u>0</u> (g)
Total of Attachment F - Section K - Post-96 Support Expense (from above)	<u>0</u> (h)

Voting Share Total for Participant's R Value: 7,177,448 (l)=(o)+(b)+(g)-(h)
(for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)

CTMEEC

PTF Revenue Requirements

Worksheet 1 of 7

Shading denotes an input

		Attachment F			
Line No.		Reference	CTMEEC	Reference	
I. INVESTMENT BASE					
1	Transmission Plant	(A)(1)(a)	51,339,755	Worksheet 3, Line 1, 1a, 1b	
2	General Plant	(A)(1)(b)	0	Worksheet 3, Line 2	
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3, Line 4	
4	Total Plant (Lines 1+2+3)		51,339,755		
5	Accumulated Depreciation	(A)(1)(d)	6,014,405	Worksheet 3, Line 5	
6	Accumulated Deferred Income Taxes	(A)(1)(e)	0	Worksheet 3, Line 8	
7	Loss On Reacquired Debt	(A)(1)(f)	0	Worksheet 3, Line 10	
8	Other Regulatory Assets	(A)(1)(g)	0	Worksheet 3, Line 13	
9	Net Investment (Line 4-5-6+7+8)		45,325,350		
10	Prepayments	(A)(1)(h)	499,181	Worksheet 3, Line 15	
11	Materials & Supplies	(A)(1)(i)	0	Worksheet 3, Line 16	
12	Cash Working Capital	(A)(1)(j)	145,825	Worksheet 3, Line 22	
13	Total Investment Base (Line 9+10+11+12)		45,970,356		
II. REVENUE REQUIREMENTS					
14	Investment Return and Income Taxes	(A)	4,137,332	Worksheet 2, IRIT	
15	Depreciation Expense	(B)	763,087	Worksheet 4, Line 3	
16	Amortization of Loss on Reacquired Debt	(C)	0	Worksheet 4, Line 4	
17	Investment Tax Credit	(D)	0	Worksheet 4, Line 5	
18	Property Tax Expense	(E)	422,869	Worksheet 4, Line 8	
19	Payroll Tax Expense	(F)	0	Worksheet 4, Line 23	
20	Operation & Maintenance Expense	(G)	835,053	Worksheet 4, Line 13	
21	Administrative & General Expense	(H)	331,544	Worksheet 4, Line 22	
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7, Col B	
23	Transmission Support Revenue	(J)	0	Worksheet 7, Col B	
24	Transmission Support Expense	(K)	0	Worksheet 7, Total	
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7, Col B	
26	Transmission Related Taxes and Fees Charge	(M)	0		
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	0		
28	Transmission Rents Received from Electric Property	(O)	0	account 454 - none	
29	Total Revenue Requirements (Line 14 thru 28)		6,489,885		

Shading denotes an input

	CAPITALIZATION 06/01/2011
LONG-TERM DEBT	\$ 22,700,000
PREFERRED STOCK	0
COMMON EQUITY	32,632,801
TOTAL INVESTMENT RETURN	\$ 55,332,801

CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
41.02%	3.79%	1.55%	0.00%
0.00%	0.00%	0.00%	0.00%
58.98%	12.64%	7.45%	7.45%
100.00%		9.00%	7.45%

	(PTF)	
INVESTMENT BASE	\$ 45,970,356	From Worksheet 1, Line 13
x Cost of Capital Rate	9.00%	
= Investment Return and Income Taxes	4,137,332	To Worksheet 1, Line 14

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Reference
<u>Transmission Plant</u>						
1	52,943,411		52,943,411	96.9710%	\$ 51,339,755	2011 YE balance sheet
2	0	100.0000% (a)	0	96.9710%	0	
3			<u>52,943,411</u>		<u>51,339,755</u>	
4	0		0	96.9710%	0	None
<u>Transmission Accumulated Depreciation</u>						
5	6,202,272		6,202,272	96.9710%	6,014,405	2011 YE balance sheet
6	0	100.0000% (a)	0	96.9710%	0	
7			<u>6,202,272</u>		<u>6,014,405</u>	
	46,741,139					
<u>Transmission Accumulated Deferred Taxes</u>						
8	0	100.0000% (c)	0	96.9710%	0	None
9	0	100.0000% (c)	0	96.9710%	0	None
10			<u>0</u>		<u>0</u>	
11	0	100.0000% (c)	0	96.9710%	0	None
<u>Other Regulatory Assets</u>						
12	0	100.0000% (a)	0	96.9710%	0	None
13	0	100.0000% (c)	0	96.9710%	0	None
14	0	100.0000% (c)	0	96.9710%	0	
15	<u>0</u>		<u>0</u>		<u>0</u>	
16	186,308	100.0000% (a)	186,308	96.9710%	499,181	2011 YE balance sheet
17	0	100.0000%	0	96.9710%	0	
18	<u>Cash Working Capital</u>					
19					835,053	Worksheet 1, Line 20
20					331,544	Worksheet 1, Line 21
21					0	Worksheet 1, Line 24
22					<u>1,166,597</u>	
23					0.125	x 45 / 360
24					<u>145,825</u>	

(a) Worksheet 5 of 8, line 11
(b) Worksheet 5 of 8, line 3
(c) Worksheet 5 of 8, line 16

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Reference
<u>Depreciation Expense</u>						
1	786,923		786,923	96.9710%	763,087	2011 YE income statement
2	0	100.0000% (a)	0	96.9710%	0	none
3			786,923		763,087	
4	0	100.0000% (c)	0	96.9710%	0	None
5	0	100.0000% (c)	0	96.9710%	0	None
<u>Property Taxes</u>						
6	436,078	100.0000%	436,078	96.9710%	422,869	2011 YE income statement
7	0	100.0000% (a)	0	96.9710%	0	
8			436,078		422,869	
<u>Transmission Operation and Maintenance</u>						
9	866,137		866,137	96.9710%	839,902	2011 YE GL
10	0		0	96.9710%	0	2011 YE GL
11	5,000		5,000	96.9710%	4,849	2011 YE GL
12	0		0	96.9710%	0	None
13	861,137		861,137	96.9710%	835,053	
<u>Transmission Administrative and General</u>						
14	341,900					
15	0					
16	0					
17	0					
18	341,900	100.0000% (c)	341,900	96.9710%	331,544	
19	0	100.0000% (c)	0	96.9710%	0	
20	0	100.0000% (c)	0	96.9710%	0	
21	0	100.0000% (c)	0	96.9710%	0	
22	341,900		341,900		331,544	
23	0	100.0000% (a)	0	96.9710%	0	Footnote (d)
(a) Worksheet 5 of 8, line 11						
(b) Worksheet 5 of 8, line 3						
(c) Worksheet 5 of 8, line 16						
(d) Payroll taxes						
Federal Unemployment	0					
FICA	0					
Medicare	0					
CT Unemployment	0					
MA Unemployment	0					
MA Universal Health	0					
VT Unemployment	0					
NH Unemployment	0					
Total	0	To Line 23				

** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments.

Shading denotes an input

Line
No.

PTF Transmission Plant Allocation Factor		CTMEEC	Reference
1	PTF Transmission Investment	\$ 51,339,736	Accounts 353--356
2	Total Transmission Investment	52,943,411	3.03% LNS
3	Percent Allocation (Line 1/Line 2)	96.9710%	
Transmission Wages and Salaries Allocation Factor			
4	Direct Transmission Wages and Salaries	1	
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 of 8
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	1	
7	Total Wages and Salaries	1	used to prevent division error in formula
8	Administrative and General Wages and Salaries	0	none
9	Affiliated Company Wages and Salaries less A&G	0	Worksheet 6 of 8
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	1	
11	Percent Allocation (Line 6/Line 10)	100.0000%	
Plant Allocation Factor			
12	Total Transmission Investment	52,943,411	Line 2
13	plus Transmission-Related General Plant (Line 2 of Wkst. 3)	0	Worksheet 3, Line 2
14	= Revised Numerator (Line 12 + Line 13)	52,943,411	
15	Total Plant in Service	52,943,411	
16	Percent Allocation (Line 14 / Line 15)	100.0000%	

Affiliated Company Wages and Salaries

 Shading denotes an input

Line		CTMEEC
"Affiliated" Transmission Wages and Salaries #560 - 573		
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11 = 1 thru 10 Total Transmission		0
12 = Total "Affiliated" Wages and Salaries		0
Less "Affiliated" Administrative and General Salaries #920 - 935		
13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
21 = 13 thru 20		0
22 = 12 less 21 Total "Affiliated" less A&G		0

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	FERC Form 1	TOTAL	
			Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	32.(g); [332.1(g) for HWP]		0
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			0
	Comerford 115 kV Substation			
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	32.1(g); [332(g) for CL&P]		0
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 394 line	332(g)		
	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			0
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310 line	330.1(n)		
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
Total =			0	0

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

**CTMEEC
TRANSCO**

Based on costs In 2011

Forecast for Rate Period June 2012 - May 2013

Additional 5 month of fixed cost to make up a full year of expense

I. FORECASTED TRANSMISSION REVENUE REQUIREMENTS		Period	POST-1996	Reference
Line No,				
1	Transmission Investment	2011	51,339,736	
2	Carrying Charge Factor		3.13%	
3	Total Forecasted Revenue Requirements (Lines 1*2)		<u>1,605,619</u>	
I. CARRYING CHARGE FACTOR				
4	Investment Return and Income Taxes		0	
5	Depreciation Expense		545,062	PTF % of 5 month est
6	Amortization of Loss on Reacquired Debt		0	
7	Investment Tax Credit		0	
8	Property Tax Expense		303,396	PTF % of 5 month est
9	Payroll Tax Expense		0	
10	Operation & Maintenance Expense		546,638	PTF % of 5 month est
11	Administrative & General Expense		210,524	PTF % of 5 month est
12	Total Expenses (Lines 4 thru 11)		<u>1,605,620</u>	
13	PTF Transmission Plant		<u>51,339,755</u>	Worksheet 1, L1
14	Carrying Charge Factor (Lines 12/13)		<u><u>3.13%</u></u>	

CTMEEC

**FERC Interest Calculation associated with Under / (Over) Collection
True Up and Interest Calculation for 2011**

Line	Annual True-up	Pre 1997	Post 1996	Total	
1	Transmission Revenue Requirements (as billed)	0	7,378,335	\$ 7,378,335	ATRR - Prior Year based on 7 month act 2011
2	True-up 2011 Actual Annual Revenue Req.	0	6,489,885	\$ 6,489,885	
3	True-up Surcharge / (Refund) (Line 2 - 1)	\$0	(\$888,450)	(\$888,450)	

	Undercollected/(Overcollected)
Pre 1997	\$0.00
Post 1996	(\$888,450)

Initial Billing Period	Balance		FERC Monthly Interest Rate	Interest	
	Pre 1997	Post 1996		Pre 1997	Post 1996
June 2011	\$0	(\$888,450)	0.27%	\$0	(\$2,399)
July 2011	\$0	(\$890,849)	0.27%	\$0	(\$2,405)
August 2011	\$0	(\$890,849)	0.28%	\$0	(\$2,494)
September 2011	\$0	(\$890,849)	0.27%	\$0	(\$2,405)
October 2011	\$0	(\$898,153)	0.28%	\$0	(\$2,515)
November 2011	\$0	(\$898,153)	0.27%	\$0	(\$2,425)
December 2011	\$0	(\$898,153)	0.28%	\$0	(\$2,515)
January 2012	\$0	(\$905,608)	0.28%	\$0	(\$2,536)
February 2012	\$0	(\$905,608)	0.26%	\$0	(\$2,355)
March 2012	\$0	(\$905,608)	0.28%	\$0	(\$2,536)
April 2012	\$0	(\$913,035)	0.27%	\$0	(\$2,465)
May 2012	\$0	(\$913,035)	0.28%	\$0	(\$2,556)
Total Undercollected/(Overcollected)				\$0	(\$918,056)

	Interest	Principal	Total
Pre 1997	\$0	\$0	\$0
Post 1996	(\$29,606)	(\$888,450)	(\$918,056)
	<u>(\$29,606)</u>	<u>(\$888,450)</u>	<u>(\$918,056)</u>

Sheet: Input Panel

EFFECTIVE JUNE 1, 2012
ISO New England Inc.
Annual Transmission Revenue Requirements
Per FERC Electric Tariff No. 3, Section II - Attachment F

Shading denotes an input

Submitted on: 14-May-12

Revenue Requirements for (year): Calendar Year 2011

Customer: Fitchburg Gas and Electric Light Company

Customer's NABs Number: 38

Name of Participant responsible for customer's billing: Fitchburg Gas and Electric Light Company

DUNs number of Participant responsible for customer's billing: 006-954-4317

	<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>
Total of Attachment F - Sections A through I =	<u>\$204,684 (a)</u>	<u>\$118,443 (f)</u>
Total of Attachment F - Section J - Support Revenue	<u>\$0 (b)</u>	<u>\$0 (g)</u>
Total of Attachment F - Section K - Support Expense	<u>\$42,152 (c)</u>	<u>\$0 (h)</u>
Total of Attachment F - Section (L through O)	<u>\$0 (d)</u>	<u>\$0 (i)</u>
Sub Total - Sum (A through I) - J + K + (L through O)	<u>\$246,836 (e)=(a)-(b)+(c)+(d)</u>	<u>\$118,443 (j)=(f)-(g)+(h)+(i)</u>
Forecasted Transmission Revenue Requirements (per Appendix C to Attachment F Implementation Rule)	<u>N/A</u>	<u>\$490,572 (m) Worksheet 1a</u>
Annual True-up (per Appendix C to Attachment F Implementation Rule)	<u>(\$2,231) (k)</u>	<u>(\$10,632) (n) Worksheet 1c</u>
Interest Charge on Annual True-up	<u>(\$74) (l)</u>	<u>(\$354) (o) Worksheet 1c</u>
Total	<u>\$244,530 (p) =(e)+(k)+(l)</u>	<u>\$598,029 (q)=(j)+(m)+(n)+(o)</u>
Annual Revenue Requirements Total = Sum of Pre-97 Revenue Requirements & Post-96 Revenue Requirements Subtotals, Forecasted Revenue Requirements & True-ups (including interest)	<u>\$842,559 (r) =(p)+(q)</u>	

Fitchburg Gas and Electric Light Company
Annual Revenue Requirements of PTF Facilities
for costs in 2011
PRE-1997

Shading denotes an input

		Attachment F			
		Reference	FG&E	Total	Reference
Line No.	I. INVESTMENT BASE	Section:			
1	Transmission Plant	(A)(1)(a)	1,244,648	1,244,648	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	58,646	58,646	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	0	0	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		1,303,294	1,303,294	
5	Accumulated Depreciation	(A)(1)(d)	621,297	621,297	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	324,293	324,293	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	0	0	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	41,145	41,145	Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		398,849	398,849	
10	Prepayments	(A)(1)(h)	44,902	44,902	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	10,668	10,668	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	16,195	16,195	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		470,614	470,614	
II.	REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	56,826	56,826	Worksheet 2
15	Depreciation Expense	(B)	44,720	44,720	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	0	0	Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)	0	0	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	14,505	14,505	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	1,228	1,228	Worksheet 4, line 17 column 5
20	Operation & Maintenance Expense	(G)	30,187	30,187	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	57,218	57,218	Worksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	0	Worksheet 7
24	Transmission Support Expense	(K)	42,152	42,152	Worksheet 7
25	Transmission Related Expense from Generators	(L)	0	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	0	0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	0	0	
28	Transmission Rents Received from Electric Property	(O)	0	0	
29	Total Revenue Requirements (Line 14 thru 28)		246,836	246,836	

Fitchburg Gas and Electric Light Company
Annual Revenue Requirements
for costs in 2011
PRE-1997

Shading denotes an input

	CAPITALIZATION 12/31/11*	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 70,000,000	56.33%	6.99%	3.94%	
PREFERRED STOCK	1,727,596	1.39%	6.86%	0.10%	0.10%
COMMON EQUITY	52,533,397	42.28%	11.64%	4.92%	4.92%
TOTAL INVESTMENT RETURN	\$ 124,260,993	100.00%		8.96%	5.02%

*See Workpaper 2

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0896

$$\begin{aligned}
 \text{(b) Federal Income Tax} &= \left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right)}{1} \right) \times \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}} \\
 &= \left(\frac{0.0502 + \left(\frac{0 + 0}{470,614} \right)}{1} \right) \times \frac{0.34}{0.34} \\
 &= \underline{0.0258606}
 \end{aligned}$$

$$\begin{aligned}
 \text{(c) State Income Tax} &= \left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right)}{1} \right) + \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}} \times \text{State Income Tax Rate} \\
 &= \left(\frac{0.0502 + \left(\frac{0 + 0}{470,614} \right)}{1} \right) + \frac{0.0258606}{0.065} \times 0.065 \\
 &= \underline{0.0052876}
 \end{aligned}$$

(a)+(b)+(c) **Cost of Capital Rate** = 0.1207482

	(PTF)	
INVESTMENT BASE	\$ 470,614	From Worksheet 1
x Cost of Capital Rate	0.1207482	
= Investment Return and Income Taxes	<u>56,826</u>	To Worksheet 1

Fitchburg Gas and Electric Light Company
PRE-1997

PTF Revenue Requirements
Worksheet 3 of 8

Shading denotes an input

Line No.		(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
1	<u>Transmission Plant</u> Transmission Plant			0		1,244,648	Line 1, Worksheet 5 Page 207.87g + (Page 201.3h + 201.6h - Total A/C 303 - Total A/C 310)*49.07% (d) (includes common plant)
2	General Plant	5,190,800	8.4814% (a)	440,253	13.3209%	58,646	
3	Total (line 1+2)			440,253		1,303,294	
4	<u>Transmission Plant Held for Future Use</u>	0		0	13.3209%	0	Page 214
5	<u>Transmission Accumulated Depreciation</u> Transmission Accum. Depreciation	4,566,219		4,566,219	13.3209%	608,262	Page 219.25b (1) Page 219.27c (includes common allocated to electric) (2)
6	General Plant Accum.Depreciation	1,153,712	8.4814% (a)	97,851	13.3209%	13,035	
7	Total (line 5+6)			4,664,070		621,297	
8	<u>Transmission Accumulated Deferred Taxes</u> Accumulated Deferred Taxes (281-283)	(28,308,693)	8.6340% (c)	(2,444,173)	13.3209%	(325,586)	Page 273.8k + 275.2k + 277.3k, See Workpaper 3
9	Accumulated Deferred Taxes (190)	112,453	8.6340% (c)	9,709	13.3209%	1,293	Page 234.8c
10	Total (line 8+9)			(2,434,464)		(324,293)	
11	<u>Transmission loss on Reacquired Debt</u>	0	8.6340% (c)	0	13.3209%	0	Page 111.81c
12	<u>Other Regulatory Assets</u> FAS 106	833,769	8.4814% (a)	70,715	13.3209%	9,420	Page 232.13f.
13	FAS 109	2,758,402	8.6340% (c)	238,160	13.3209%	31,725	Page 232.1f - 278.1e
14	Other Regulatory Liabilities (254.DK)	0	8.6340% (c)	0	13.3209%	0	
15	Total (line 12+13+14)	3,592,171		308,875		41,145	
16	<u>Transmission Prepayments</u>	3,974,345	8.4814% (a)	337,080	13.3209%	44,902	Page 111.57c *p.200.8.c/p.200.8.b
17	<u>Transmission Materials and Supplies</u>	80,081		80,081	13.3209%	10,668	Page 227.8c
18	<u>Cash Working Capital</u>						
19	Operation & Maintenance Expense					30,187	Worksheet 1, Line 20
20	Administrative & General Expense					57,218	Worksheet 1, Line 21
21	Transmission Support Expense					42,152	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					129,557	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					16,195	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

(d) 49.07% is FGE's gas and electric labor allocator used for allocating common plant. See Workpaper 4.

(1) Adjusted by \$33,554.42 to exclude prior period depreciation rate change.

(2) Adjusted by \$16,319.93 to exclude prior period depreciation rate change.

Fitchburg Gas and Electric Light Company PTF Revenue Requirements

PRE-1997

Worksheet 4 of 8

(2)

(4)

Shading denotes an input

Line No.	(1) Total	Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
<u>Depreciation Expense</u>						
1	319,017		319,017	13.3209%	42,496	Page 336.7b
2	196,820	8.4814% (a)	16,693	13.3209%	2,224	Page 336.10b (includes common allocated to electric)
3			335,710		44,720	
4	0	8.6340% (c)	0	13.3209%	0	Page 117.64c
5	0	8.6340% (c)	0	13.3209%	0	Page 266.8f
<u>Property Taxes</u>						
6	1,261,174	8.6340% (c)	108,890	13.3209%	14,505	Page 263i, lines 9, 10, 11 & 16
7	0	8.4814% (a)	0	13.3209%	0	Page 262-263
8			108,890		14,505	
<u>Transmission Operation and Maintenance</u>						
9	5,385,201		5,385,201	0.133209	717,357	Page 321.112b
10	5,028,000		5,028,000	0.133209	669,775	Page 321.96b
11	130,586		130,586	0.133209	17,395	Page 321.84b
12	0		0	0.133209	0	Page 321.85b & .90b
13	226,615		226,615	13.3209%	30,187	
<u>Transmission Administrative and General</u>						
14	5,236,710					Page 323.197b
15	35,606					Page 323.185b
16	276,830					Page 323.189b
17	0					Page 323.191b
18	4,924,274	8.4814% (a)	417,647	13.3209%	55,634	
19	35,606	8.6340% (c)	3,074	13.3209%	409	
20	8,819		8,819	13.3209%	1,175	Page 351.6h
21	0	8.6340% (c)	0	13.3209%	0	
22	4,968,699		429,540		57,218	
23	108,725	8.4814% (a)	9,221	13.3209%	1,228	Footnote (d)
(a) Worksheet 5 of 8, line 11						
(b) Worksheet 5 of 8, line 3						
(c) Worksheet 5 of 8, line 16						
(d) Payroll taxes FERC Form 1, page 263.i ,263.1i						
Federal Unemployment	1,715					Page 263.4i
FICA	184,307					Page 263.2i
Medicare	0					
State Unemployment	9,971					Page 263.6i
MA Universal Health	0					Page 263.8i
Payroll Taxes Capitalized	(87,268)					Page 263.15i
Total	108,725	To Line 23				

** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments.

Shading denotes an input

Line
No.

FERC Form 1
Reference

PTF Transmission Plant Allocation Factor

FG&E

1	PTF Transmission Investment	1,244,648
2	Total Transmission Investment	9,343,602
3	Percent Allocation (Line 1/Line 2)	13.3209%

See Workpaper 1
Page 207.58g

Transmission Wages and Salaries Allocation Factor

4	Direct Transmission Wages and Salaries	85,997
5	Affiliated Company Transmission Wages and Salaries	0
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	85,997
7	Total Wages and Salaries	1,058,819
8	Administrative and General Wages and Salaries	44,872
9	Affiliated Company Wages and Salaries less A&G	0
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	1,013,947
11	Percent Allocation (Line 6/Line 10)	8.4814%

Page 354.21b
Worksheet 6 of 8

Page 354.28b + Line 5
Page 354.27b
Worksheet 6 of 8

Plant Allocation Factor

12	Total Transmission Investment	9,343,602
13	plus Transmission-Related General Plant (Line 2 of Wkst. 3)	440,253
14	= Revised Numerator (Line 12 + Line 13)	9,783,855
15	Total Plant in Service	113,317,588
16	Percent Allocation (Line 14 / Line 15)	8.6340%

Page 207.58g
Worksheet 3, Line 2, col.(3)

Page 207.95g + ((Page 201.3h + 201.6h - Total A/C 303 - Total A/C 310)*.4907) (a)

(a) 49.07% is FGE's gas and electric labor allocator used for allocating common plant. See Workpaper 4.

Affiliated Company Wages and Salaries

PRE-1997

Shading denotes an input

Line		FG&E	
"Affiliated" Transmission Wages and Salaries #560 - 573			
1	560	0	
2	562	0	
3	564	0	
4	566	0	
5	568	0	
6	569	0	
7	570	0	
8	571	0	
9	572	0	
10	573	0	
11 = 1 thru 10	Total Transmission	0	
12 = Total "Affiliated" Wages and Salaries			
Less "Affiliated" Administrative and General Salaries #920 - 935			
13	920	0	
14	921	0	
15	923	0	
16	925	0	
17	926	0	
18	928	0	
19	930	0	
20	935	0	
21 = 13 thru 20		0	
22 = 12 less 21	Total "Affiliated" less A&G	0	

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	FG&E		TOTAL	
		Revenues (a)	Expenses (b)	Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line				
	115 kV Somerville 402 Substation				
	115/345 kV North Cambridge 509 Substation				
	345 kV Golden Hills -Mystic 389 (x&y) line				
	West Medway 345 kV breaker				
	115 kV Millbury-Medway 201 line				
	HQ Phase II - AC in MA	0	1,972	0	1,972
	345 kV "stabilizer" 342 line				
	345 kV Walpole - Medway 325 line				
	345 kV Carver - Walpole 331 line				
	345 kV Jordan Rd - Canal 342 line				
CEC	Second Canal line				
	345 kV Pilgrim-Bridgewater - 355 line				
	345 kV Myles Standish - Canal 342 line				
CMP	345 kV Buxton-South Gorham 386 line	0	0	0	0
	115 kV Wyman 164-167 lines	0	0	0	0
	115 kV Maine Yankee transmission				
EUA	345 kV Carver - Walpole 331 line				
	345 kV Medway - Bridgewater 344 Line				
	Northern Rhode Island transmission				
NEP	Chester SVC	0	11,907	0	11,907
	Comerford 115 kV Substation				
	345 kV Sandy-Tewksbury 337 line				
	345 kV Tewksbury-Woburn 338 line				
	115 kV Tewksbury - Woburn M139 line				
	115 kV Tewksbury - Woburn N140 line				
	Moore 115 kV Substation				
	HQ Phase II - AC in MA	0	28,272	0	28,272
	345 kV Golden Hills-Mystic 349 line				
	345 kV NH/MA border-Tewksbury 394 line				
	115 kV Read - Washington V148 line				
NU	345 kV 363, 369 and 394 Seabrook lines				
	Fairmont 115 kV Substation				
	345 kV Millstone-Manchester 310 line				
	UI Substations				
	Black Pond				
Total =		0	42,152	0	42,152

Amount by which Support Expense exceeds Support Reven 42,152
(To Worksheet 3, Line 21, Column 5)

Summary of Fitchburg Gas and Electric Light Company System
Monthly Coincident Peaks for 2011
(Megawatts)
PRE-1997

Shading denotes an input

	JAN '11	FEB '11	MAR '11	APR '11	MAY '11	JUN '11	JUL '11	AUG '11	SEP '11	OCT '11	NOV '11	DEC '11
Day	24	2	9	4	31	8	22	8	14	27	1	19
Hour	19:00	18:00	19:00	20:00	17:00	17:00	12:00	17:00	20:00	19:00	19:00	18:00
FG&E	82	77	74	68	74	86	94	84	75	67	68	73

Annual FG&E System Average 12 CP Load **77**

NOTE: Numbers represent FERC Form 1 Pages 401/401b coincident peaks.

Fitchburg Gas and Electric Light Company
Annual Revenue Requirements of PTF Facilities
for costs in 2011
POST-1996

Shading denotes an input

		Attachment F				
		Reference	Post-1996	Post-2003	Total	Reference
Line No.	I. INVESTMENT BASE	Section:				
1	Transmission Plant	(A)(1)(a)	722,465	602,905		Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	34,041	n/a		Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	0	n/a		Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		756,506	602,905		
5	Accumulated Depreciation	(A)(1)(d)	360,635	300,954 (1)		Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	188,237	121,382 (2)		Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	0	n/a		Worksheet 3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	23,883	n/a		Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		231,517	180,569		
10	Prepayments	(A)(1)(h)	26,064	n/a		Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	6,192	n/a		Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	6,342	n/a		Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		270,115	180,569		
II.	REVENUE REQUIREMENTS					
14	Investment Return and Income Taxes	(A)	32,616	0 (3)	32,616	Worksheet 2, Worksheet 2a
15	Depreciation Expense	(B)	25,958		25,958	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	0		0	Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)	0		0	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	8,420		8,420	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	713		713	Worksheet 4, line 17 column 5
20	Operation & Maintenance Expense	(G)	17,523		17,523	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	33,213		33,213	Worksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0		0	Worksheet 7
23	Transmission Support Revenue	(J)	0		0	Worksheet 7
24	Transmission Support Expense	(K)	0		0	Worksheet 7
25	Transmission Related Expense from Generators	(L)	0		0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	0		0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	0		0	
28	Transmission Rents Received from Electric Property	(O)	0		0	
29	Total Revenue Requirements (Line 14 thru 28)		118,443	0	118,443	

(1) Worksheet 3, Line 7, Column 3 x Post-03 PTF Allocation Factor, Worksheet 5, Line 3.

(2) See Workpaper 5.

(3) No eligible projects for the 100 basis point adder.

Fitchburg Gas and Electric Light Company
Forecasted Revenue Requirements of PTF Facilities

PTF Revenue Requirements
Worksheet 1a

Sheet: Worksheet 1a

POST-2003

Shading denotes an input

I. <u>FORECASTED TRANSMISSION REVENUE REQUIREMENTS</u>		<u>Period</u>	Attachment F Reference Section:	FG&E	<u>Reference</u>
Line No.					
1	Forecasted Transmission Plant Additions	2012	Appendix C	\$2,992,334	Workpaper 1, Page 7
2	Carrying Charge Factor		Appendix C	16.39%	
3	Total Forecasted Revenue Requirements (Lines 1*2)			<u>\$490,572</u>	
II. <u>CARRYING CHARGE FACTOR</u>					
4	Investment Return and Income Taxes		(A)	\$32,616	Worksheet 1, line 14
5	Depreciation Expense		(B)	\$25,958	Worksheet 1, line 15
6	Amortization of Loss on Reacquired Debt		(C)	\$0	Worksheet 1, line 16
7	Investment Tax Credit		(D)	\$0	Worksheet 1, line 17
8	Property Tax Expense		(E)	\$8,420	Worksheet 1, line 18
9	Payroll Tax Expense		(F)	\$713	Worksheet 1, line 19
10	Operation & Maintenance Expense		(G)	\$17,523	Worksheet 1, line 20
11	Administrative & General Expense		(H)	<u>\$33,213</u>	Worksheet 1, line 21
12	Total Expenses (Lines 4 thru 11)			\$118,443	
13	PTF Transmission Plant		(A)(1)(a)	<u>\$722,465</u>	Worksheet 5, Line 1, Pre-2004 plus Post-2003
14	Carrying Charge Factor (Lines 12/13)			<u>16.39%</u>	

Fitchburg Gas and Electric Light Company
Transmission Revenue Requirements of PTF Facilities
2011 True-up
POST-2003

I. <u>ANNUAL TRUE-UP PER ATTACHMENT F</u>			<u>Period</u>	Attachment F Reference Section:	<u>FG&E</u>		<u>Reference</u>
					Pre-97	Post 96	
Line No.	1	Transmission Revenue Requirements (as billed)	6/11 - 5/12		\$ 249,067	\$ 129,075	ATRR - Prior Year Voting Share (e), (j)
	2	True-up 2011 Actual Annual RR			\$ 246,836	\$ 118,443	
	3	Over/(Under) (Line 1 - Line 2)			\$ 2,231	\$ 10,632	
	4	Over/(Under) June 1, 2011 - May 31, 2012			\$ 2,231	\$ 10,632	

Fitchburg Gas and Electric Light Company
FERC Interest Calculation associated with Under / (Over)
Transmission Revenue Requirements of PTF Facilities
PRE-1997

PRE97	\$	Under / (Over)	(2,231)						
Post 1996	\$		(10,632)						
<u>Initial Billing Period</u>		<u>PRE97 Balance</u>		<u>Post 1996 Balance</u>		<u>Monthly Interest Rate</u>		<u>PRE97 Interest</u>	<u>Post 1996 Interest</u>
June 2011	\$	(2,231)	\$	(10,632)		0.27%	\$	(6)	\$ (29)
July 2011	\$	(2,237)	\$	(10,661)		0.27%	\$	(6)	\$ (29)
August 2011	\$	(2,237)	\$	(10,661)		0.28%	\$	(6)	\$ (30)
September 2011	\$	(2,237)	\$	(10,661)		0.27%	\$	(6)	\$ (29)
October 2011	\$	(2,256)	\$	(10,748)		0.28%	\$	(6)	\$ (30)
November 2011	\$	(2,256)	\$	(10,748)		0.27%	\$	(6)	\$ (29)
December 2011	\$	(2,256)	\$	(10,748)		0.28%	\$	(6)	\$ (30)
January 2012	\$	(2,274)	\$	(10,837)		0.28%	\$	(6)	\$ (30)
February 2012	\$	(2,274)	\$	(10,837)		0.26%	\$	(6)	\$ (28)
March 2012	\$	(2,274)	\$	(10,837)		0.28%	\$	(6)	\$ (30)
Apr-2012	\$	(2,293)	\$	(10,926)		0.27%	\$	(6)	\$ (30)
May-2012	\$	(2,293)	\$	(10,926)		0.28%	\$	(6)	\$ (31)
Total Interest							\$	(74)	\$ (354)
True-Up							\$	(2,231)	\$ (10,632)
Total True-Up & Interest							\$	(2,305)	\$ (10,986)

Fitchburg Gas and Electric Light Company
Annual Revenue Requirements
for costs in 2011
POST-1996

Shading denotes an input

	CAPITALIZATION 12/31/11*	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 70,000,000	56.33%	6.99%	3.94%	
PREFERRED STOCK	\$ 1,727,596	1.39%	6.86%	0.10%	0.10%
COMMON EQUITY	\$ 52,533,397	42.28%	11.64%	4.92%	4.92%
TOTAL INVESTMENT RETURN	\$ 124,260,993	100.00%		8.96%	5.02%

*See Workpaper 2

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0896

(b) Federal Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right)}{1} \right) \times \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}}$$

=
$$\left(\frac{0.0502 + \left(\frac{0 + 0}{270,115} \right)}{1} \right) \times \frac{0.34}{0.34}$$

= 0.0258606

(c) State Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right)}{1} \right) + \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}} \times \text{State Income Tax Rate}$$

=
$$\left(\frac{0.0502 + \left(\frac{0 + 0}{270,115} \right)}{1} \right) + \frac{0.0258606}{0.065} \times 0.065$$

= 0.0052876

(a)+(b)+(c) **Cost of Capital Rate** = 0.1207482

	(PTF)	
INVESTMENT BASE	\$ 270,115	From Worksheet 1, Line 13, Post-96
x Cost of Capital Rate	0.1207482	
= Investment Return and Income Taxes	<u>32,616</u>	To Worksheet 1

Fitchburg Gas and Electric Light Company

POST-1996

PTF Revenue Requirements

Worksheet 3 of 8

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
1	<u>Transmission Plant</u> Transmission Plant		0		722,465	Line 1, Worksheet 5
2	General Plant	8.4814% (a)	440,253	7.7322%	34,041	Page 207.99g + (Page 201.3h + 201.6h -
3	Total (line 1+2)		440,253		756,506	A/C 303 Common - Total A/C 310)*49.07% (d) (includes common plant)
4	<u>Transmission Plant Held for Future Use</u>		0	7.7322%	0	Page 214
5	<u>Transmission Accumulated Depreciation</u> Transmission Accum. Depreciation		4,566,219	7.7322%	353,069	Page 219.25b (1)
6	General Plant Accum. Depreciation	8.4814% (a)	97,851	7.7322%	7,566	Page 219.28c (includes common allocated
7	Total (line 5+6)		4,664,070		360,635	to electric) (2)
8	<u>Transmission Accumulated Deferred Taxes</u> Accumulated Deferred Taxes (281-283)	8.6340% (c)	(2,444,173)	7.7322%	(188,988)	Page 273.8k + 275.2k + 277.3k, See Workpaper 3
9	Accumulated Deferred Taxes (190)	8.6340% (c)	9,709	7.7322%	751	Page 234.8c
10	Total (line 8+9)		(2,434,464)		(188,237)	
11	<u>Transmission loss on Reacquired Debt</u>	8.6340% (c)	0	7.7322%	0	Page 111.81c
12	<u>Other Regulatory Assets</u> FAS 106	8.4814% (a)	70,715	7.7322%	5,468	Page 232.16f
13	FAS 109	8.6340% (c)	238,160	7.7322%	18,415	Page 232.1f - 278.1f
14	Other Regulatory Liabilities (254.DK)	8.6340% (c)	0	7.7322%	0	
15	Total (line 12+13+14)		308,875		23,883	
16	<u>Transmission Prepayments</u>	8.4814% (a)	337,080	7.7322%	26,064	Page 111.57c *p.200.8.c/p.200.8.b
17	<u>Transmission Materials and Supplies</u>		80,081	7.7322%	6,192	Page 227.8c
18	<u>Cash Working Capital</u>					
19	Operation & Maintenance Expense				17,523	Worksheet 1, Line 20
20	Administrative & General Expense				33,213	Worksheet 1, Line 21
21	Transmission Support Expense				0	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)				50,736	
23					0.125	x 45 / 360
24	Total (line 22 * line 23)				6,342	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

(d) 49.07% is FGE's gas and electric labor allocator used for allocating common plant. See Workpaper 4.

(1) Adjusted by \$33,554.42 to exclude prior period depreciation rate change.

(2) Adjusted by \$16,319.93 to exclude prior period depreciation rate change.

Fitchburg Gas and Electric Light Company PTF Revenue Requirements

POST-1996

Worksheet 4 of 8

(2)

(4)

Shading denotes an input

Line No.	(1) Total	Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
<u>Depreciation Expense</u>						
1	319,017		319,017	7.7322%	24,667	Page 336.7b
2	196,820	8.4814% (a)	16,693	7.7322%	1,291	Page 336.10b (includes common allocated to electric)
3			335,710		25,958	
4	0	8.6340% (c)	0	7.7322%	0	Page 117.64c
5	0	8.6340% (c)	0	7.7322%	0	Page 266.8f
<u>Property Taxes</u>						
6	1,261,174	8.6340% (c)	108,890	7.7322%	8,420	Page 263i, lines 9, 10, 11 & 16
7		8.4814% (a)	0	7.7322%	0	Page 262-263
8			108,890		8,420	
<u>Transmission Operation and Maintenance</u>						
9	5,385,201		5,385,201	7.7322%	416,395	Page 321.112b
10	5,028,000		5,028,000	7.7322%	388,775	Page 321.96b
11	130,586		130,586	7.7322%	10,097	Page 321.84b to 321.88b
12	0		0	7.7322%	0	Page 321.93b & .98b
13	226,615		226,615	7.7322%	17,523	
<u>Transmission Administrative and General</u>						
14	5,236,710					Page 323.197b
15	35,606					Page 323.185b
16	276,830					Page 323.189b
17	0					Page 323.191b
18	4,924,274	8.4814% (a)	417,647	7.7322%	32,293	
19	35,606	8.6340% (c)	3,074	7.7322%	238	
20	8,819		8,819	7.7322%	682	Page 351.6h
21	0	8.6340% (c)	0	7.7322%	0	
22	4,968,699		429,540		33,213	
23	108,725	8.4814% (a)	9,221	7.7322%	713	Footnote (d)
(a) Worksheet 5 of 8, line 11						
(b) Worksheet 5 of 8, line 3						
(c) Worksheet 5 of 8, line 16						
(d) Payroll taxes FERC Form 1, page 263.i ,263.1i						
	1,715					Page 263.4i
	184,307					Page 263.2i
	0					
	9,971					Page 263.6i
	0					Page 263.8i
	(87,268)					Page 263.15i
Total	108,725	To Line 23				

** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments.

POST-1996

Shading denotes an input

Line
No.FERC Form 1
Reference**PTF Transmission Plant Allocation Factor****Post-1996****Post-2003****Total
Post-96**

1	PTF Transmission Investment	119,560	602,905	722,465	See Workpaper 1 Page 207.58g
2	Total Transmission Investment	9,343,602	9,343,602	9,343,602	
3	Percent Allocation (Line 1/Line 2)	1.2796%	6.4526%	7.7322%	

1,967,113
21.0531%**Transmission Wages and Salaries Allocation Factor**

4	Direct Transmission Wages and Salaries	85,997			Page 354.21b Worksheet 6 of 8
5	Affiliated Company Transmission Wages and Salaries	0			
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	85,997			
7	Total Wages and Salaries	1,058,819			Page 354.28b + Line 5 Page 354.27b Worksheet 6 of 8
8	Administrative and General Wages and Salaries	44,872			
9	Affiliated Company Wages and Salaries less A&G	0			
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	1,013,947			
11	Percent Allocation (Line 6/Line 10)	8.4814%			

Plant Allocation Factor

12	Total Transmission Investment	9,343,602			Page 207.58g Worksheet 3, Line 2, col.(3)
13	plus Transmission-Related General Plant (Line 2 of Wkst. 3)	440,253			
14	= Revised Numerator (Line 12 + Line 13)	9,783,855			
15	Total Plant in Service	113,317,588			Page 207.104g + ((Page 201.3h + 201.6h - Total A/C 303 - Total A/C 310)*.4907) (a)
16	Percent Allocation (Line 14 / Line 15)	8.6340%			

(a) 49.07% is FGE's gas and electric labor allocator used for allocating common plant. See Workpaper 4.

Affiliated Company Wages and Salaries

POST-1996

Shading denotes an input

Line		Post-1996	
"Affiliated" Transmission Wages and Salaries #560 - 573			
1	560	0	
2	562	0	
3	564	0	
4	566	0	
5	568	0	
6	569	0	
7	570	0	
8	571	0	
9	572	0	
10	573	0	
11 = 1 thru 10	Total Transmission	0	
12 = Total "Affiliated" Wages and Salaries			
Less "Affiliated" Administrative and General Salaries #920 - 935			
13	920	0	
14	921	0	
15	923	0	
16	925	0	
17	926	0	
18	928	0	
19	930	0	
20	935	0	
21 = 13 thru 20		0	
22 = 12 less 21	Total "Affiliated" less A&G	0	

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	FG&E		TOTAL	
		Revenues (a)	Expenses (b)	Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line				
	115 kV Somerville 402 Substation				
	115/345 kV North Cambridge 509 Substation				
	345 kV Golden Hills -Mystic 389 (x&y) line				
	West Medway 345 kV breaker				
	115 kV Millbury-Medway 201 line				
	HQ Phase II - AC in MA				
	345 kV "stabilizer" 342 line				
	345 kV Walpole - Medway 325 line				
	345 kV Carver - Walpole 331 line				
	345 kV Jordan Rd - Canal 342 line				
CEC	Second Canal line				
	345 kV Pilgrim-Bridgewater - 355 line				
	345 kV Myles Standish - Canal 342 line				
CMP	345 kV Buxton-South Gorham 386 line				
	115 kV Wyman 164-167 lines				
	115 kV Maine Yankee transmission				
EUA	345 kV Carver - Walpole 331 line				
	345 kV Medway - Bridgewater 344 Line				
	Northern Rhode Island transmission				
NEP	Chester SVC				
	Comerford 115 kV Substation				
	345 kV Sandy-Tewksbury 337 line				
	345 kV Tewksbury-Woburn 338 line				
	115 kV Tewksbury - Woburn M139 line				
	115 kV Tewksbury - Woburn N140 line				
	Moore 115 kV Substation				
	HQ Phase II - AC in MA				
	345 kV Golden Hills-Mystic 349 line				
	345 kV NH/MA border-Tewksbury 394 line				
	115 kV Read - Washington V148 line				
NU	345 kV 363, 369 and 394 Seabrook lines				
	Fairmont 115 kV Substation				
	345 kV Millstone-Manchester 310 line				
	UI Substations				
	Black Pond				
Total =		0	0	0	0

Summary of Fitchburg Gas and Electric Light Company System
Monthly Coincident Peaks for 2011
(Megawatts)
POST-1996

Shading denotes an input

	JAN '11	FEB '11	MAR '11	APR '11	MAY '11	JUN '11	JUL '11	AUG '11	SEP '11	OCT '11	NOV '11	DEC '11
Day	24	2	9	4	31	8	22	8	14	27	1	19
Hour	19:00	18:00	19:00	20:00	17:00	17:00	12:00	17:00	20:00	19:00	19:00	18:00
FG&E	82	77	74	68	74	86	94	84	75	67	68	73

Annual FG&E System Average 12 CP Load **77**

NOTE: Numbers represent FERC Form 1 Pages 401/401b coincident peaks.

Workpaper 1
Detail of PTF Transmission Plant as of 12/31/11

Date	Description	In Service	Value	Classification	PTF	Non-PTF	PTF XMFR	Non-PTF XMFR	Common	
						1	2	3	4	5
<u>Land</u>										
1977	Cost of Land purchased from New England Power Co.		6,663.35	5		0	0	0	0	6663.35
Oct-78	Acquisition Costs for land at Flagg Pond Sub		817.70	5		0	0	0	0	817.7
<u>Improvements</u>										
Aug-65	Structures and Improvements		24,143.99	5		0	0	0	0	24143.99
Nov-77	Purchased from NEP on 6/1/77, Tx Portion S/N's 6994207 & 34891		443,407.08	4		0	0	0	443407.08	0
	Purchased from NEP on 6/1/77, 115 kV Portion		414,449.05	1	414449.05	0	0	0	0	0
	Purchased from NEP on 6/1/77, 69 kV Portion		414,449.05	2	0	414449.05	0	0	0	0
Oct-78	Transfer acquisition costs to acct 2-353-99, Tx's		(29,370.17)	4	0	0	0	-29370.17	0	0
	Transfer acquisition costs to acct 2-353-99, 115		(27,452.06)	1	-27452.06	0	0	0	0	0
	Transfer acquisition costs to acct 2-353-99, 69		(27,452.06)	2	0	-27452.06	0	0	0	0
Dec-81	Retire 2 600 amp OCB plus installation		(21,975.62)	1	-21975.62	0	0	0	0	0
Oct-82	Install 115kv breaker status for REMVEC		14,556.40	1	14556.4	0	0	0	0	0
Nov-82	See F-2172		924,949.40	1	924949.4	0	0	0	0	0
Jun-83	Install 2 1000w Lucalox Floodlights near control shack		2,938.12	5	0	0	0	0	2938.12	0
Nov-84	Install Potential Transformers		21,174.57	5	0	0	0	0	21174.57	0
Nov-84	Retire PT	1977	(4,628.41)	5	0	0	0	0	-4628.41	0
Jun-85	Metering		41,916.83	5	0	0	0	0	41916.83	0
Sep-88	Install #27 & #28 airbreak switch on #2 Feeder		17,310.44	2	0	17310.44	0	0	0	0
Sep-88	Retire #27 & #28 airbreak switch on #2 Feeder	1977	(5,762.36)	2	0	-5762.36	0	0	0	0
Jul-91	Adjust to above entry		183.25	2	0	183.25	0	0	0	0
Feb-90	Install PT on 02 Line		8,435.83	2	0	8435.83	0	0	0	0
Feb-90	Retire PT on 02 Line	1984	(21,174.57)	2	0	-21174.57	0	0	0	0
Dec-89	Install 2016 of 4/0 st bare copper		1,868.89	5	0	0	0	0	1868.89	0
Dec-89	Install 50' of 2" PVC Pipe		4,033.47	5	0	0	0	0	4033.47	0
Dec-89	785' of 4/0 st 600 volt	1977	(1,198.75)	5	0	0	0	0	-1198.75	0
Dec-89	50' of 4/0 wire	1977	(31.55)	5	0	0	0	0	-31.55	0
Dec-89	760' of 4/0 hard drawn wire	1977	(1,310.88)	5	0	0	0	0	-1310.88	0
Dec-89	50' of 4/0 wire	1977	(106.74)	5	0	0	0	0	-106.74	0
Dec-89	965' of 4/0 wire	1977	(2,876.75)	5	0	0	0	0	-2876.75	0
Dec-89	50' of 2" PVC Pipe	1977	(164.50)	5	0	0	0	0	-164.5	0
Aug-91	GE 69kv Bushing in OCB s/n 0139A4928-201	1977	(14,231.56)	2	0	-14231.56	0	0	0	0
Aug-91	69kv 1200amp bushing in OCB		2,405.57	2	0	2405.57	0	0	0	0
Feb-87	Data Star Recorders		3,780.00	5	0	0	0	0	3780	0
Mar-87	Installed Data Star Recorder Software Level #2		750.00	5	0	0	0	0	750	0
1987	Payroll & overheads for above install		1,014.38	5	0	0	0	0	1014.38	0
1978	Recorder Tape System GE	1978	(5,300.00)	5	0	0	0	0	-5300	0
1978	Universal Mag Tape Cartridges	1978	(637.20)	5	0	0	0	0	-637.2	0
Aug-90	Watt/Var Transducer		5,950.00	5	0	0	0	0	5950	0
Aug-90	Volt Transducer		185.00	5	0	0	0	0	185	0
Aug-90	Shipping & Handling		34.92	5	0	0	0	0	34.92	0
Aug-90	500' 4/C #12 AWG Control Cable		1,142.10	5	0	0	0	0	1142.1	0
Aug-90	50' 1/2 watt precision resistors		41.39	5	0	0	0	0	41.39	0
Aug-90	350' T&B Stakon Terminals		86.45	5	0	0	0	0	86.45	0
Aug-90	69' Copper Wire		10.35	5	0	0	0	0	10.35	0
Aug-90	Cable Tie		17.55	5	0	0	0	0	17.55	0
Aug-90	Misc Parts		52.76	5	0	0	0	0	52.76	0
Aug-90	Labor for fixing recorder		368.80	5	0	0	0	0	368.8	0
Aug-90	Labor for wiring		124.20	5	0	0	0	0	124.2	0
Jun-92	Install GETEC Telemetry to REMVAC (Liabilities)		422.31	5	0	0	0	0	422.31	0
Jun-92	Overheads		6,638.54	5	0	0	0	0	6638.54	0
Jun-92	Payroll		8,030.61	5	0	0	0	0	8030.61	0
Nov-91	Bristol DPC 333010A computer		4,230.71	5	0	0	0	0	4230.71	0
Nov-91	Bristol SLC 371140A Recorders		5,771.41	5	0	0	0	0	5771.41	0
Oct-91	Bristol Power Supply		515.05	5	0	0	0	0	515.05	0
Sep-91	Labor to set up Bristol		2,355.00	5	0	0	0	0	2355	0
Aug-90	Spare Interrupter Assembly for 115kv Circuit breaker		9,512.00	2	0	9512	0	0	0	0
1993	Retire Westinghouse auto transformer	1977	(152,101.77)	4	0	0	0	-152101.77	0	0
1992	Redesign Rewind & Rebuild 30/40/50 MVA West		0.00	4	0	0	0	0	0	0
	Auto Transformer s/n 34891 includes all charges		514,480.75	4	0	0	0	514480.75	0	0
1992	Purch used Auto Transformer 24/40 mva Magntek		200,032.04	4	0	0	0	200032.04	0	0

Date	Description	In Service	Value	Classification	PTF	Non-PTF	PTF XMFR	Non-PTF XMFR	Common	5
Land						1	2	3	4	
Apr-94	Fused Disconnect	1977	(505.26)	5		0	0	0	0	-505.26
May-94	Replace Fused Disconnect		434.21	5		0	0	0	0	434.21
Sep-94	Install & purch EM-GRO Air Compressor		1,273.97	5		0	0	0	0	1273.97
Sep-94	Install Deadend Structure 3-arrestors & 6-bushings		30,233.66	5		0	0	0	0	30233.66
Sep-95	Construct 115 Kv facilities & connect spare transformer in place of failed #1 autotrans.		0.00	2		0	0	0	0	0
	Repair and rewinding of 115-69 KV #1 Autotransformer		237,601.84	2		0	237601.84	0	0	0
	including uprating to a rated capacity of 60/80/100 MVA		0.00	3		0	0	0	0	0
	Insurance Recovery less deductible of \$25K		335,776.00	4		0	0	0	335776	0
	Lightning arrestors, delivery and testing		(321,696.66)	4		0	0	0	-321696.66	0
Nov-95	60/80/100 MVA 115-69KV Autotransformer (1996) S/N=MNL9258		6,840.09	2		0	6840.09	0	0	0
Sep-96	Installation cost for above (1996)		544,772.08	4		0	0	0	544772.08	0
Sep-96	Current Transformers	1977	42,610.39	4		0	0	0	42610.39	0
Nov-97	Autotransformer Disconnect Switch	1977	(8,000.00)	5		0	0	0	0	-8000
Mar-98	D-30 Oil Circuit Breaker	1977	(2,700.00)	2		0	-2700	0	0	0
May-98	Disconnect Switch for above	1977	(14,590.00)	2		0	-14590	0	0	0
May-98	C29 Breaker Disconnect Switch	1977	(2,700.00)	2		0	-2700	0	0	0
Aug-00	Three Phase overcurrent relays	1977	(5,858.61)	2		0	-5858.61	0	0	0
	Ground overcurrent relays	1977	(2,100.00)	2		0	-2100	0	0	0
Nov-05	Retire Meters & Relays, Control Power System	1978	(1,400.00)	2		0	-1400	0	0	0
Nov-05	Retire Ann. & events Recorder, Rochester Instrument #449-1462	1978	(25,490.00)	1		-25490	0	0	0	0
Nov-05	Retire 200 Ampere Hour Battery, Excide	1978	(15,400.00)	1		-15400	0	0	0	0
Nov-05	Retire Engineering Services and Testing Services	1978	(3,042.00)	1		-3042	0	0	0	0
Nov-05	Retire Antenna Installed	1978	(11,269.53)	1		-11269.53	0	0	0	0
Nov-05	Retire Encoders Installed	1978	(302.00)	1		-302	0	0	0	0
Nov-05	Retire AC Power Surge Kit	1978	(547.00)	1		-547	0	0	0	0
Nov-05	Retire Coaxial Antenna, Lead, Fittings & Installation of Antenna	1978	(21.00)	1		-21	0	0	0	0
Nov-05	Retire BBA15-AA11 Desk Top 50 Watt #6161 4030A	1978	(261.35)	1		-261.35	0	0	0	0
Nov-05	Retire B169 AC Power Surge Kit MI 559429	1978	(1,195.00)	1		-1195	0	0	0	0
Nov-05	Retire Sales Tax on Above	1978	(21.00)	1		-21	0	0	0	0
Nov-05	Retire Cleverdon, Varney & Pike Invoices	1978	(10.03)	1		-10.03	0	0	0	0
Nov-05	Retire Cleverdon, Varney & Pike Engineering Services Invoices	1978	(14,094.12)	1		-14094.12	0	0	0	0
Nov-05	Retire General Electric Company Invoices for computer services	1978	(9,047.75)	1		-9047.75	0	0	0	0
Nov-05	Retire Events Recorder & Accessories (from Rochester Instruments)	1978	(76.19)	1		-76.19	0	0	0	0
Nov-05	Retire Metering	1984	(69.24)	1		-69.24	0	0	0	0
Nov-05	Retire 'Watt/Var Transducer	Aug-90	(20,742.26)	1		-20742.26	0	0	0	0
Nov-05	Retire Volt Transducer	Aug-90	(5,950.00)	5		0	0	0	0	-5950
Nov-05	Retire Shipping & Handling	Aug-90	(185.00)	5		0	0	0	0	-185
Nov-05	Labor for fixing recorder	Aug-90	(34.92)	5		0	0	0	0	-34.92
Nov-05	Labor for wiring	Aug-90	(368.80)	5		0	0	0	0	-368.8
Nov-05	Retire 'Install GETEC Telemetry to REMVAC (Liabilities)	Aug-90	(124.20)	5		0	0	0	0	-124.2
Nov-05	Retire Overheads	Aug-90	(422.31)	5		0	0	0	0	-422.31
Nov-05	Retire 'Payroll	Aug-90	(6,638.54)	5		0	0	0	0	-6638.54
Nov-05	Retire Duct Tone Receivers Installed	1978	(8,030.61)	5		0	0	0	0	-8030.61
Nov-05	Retire B166 Emergency Power Option #CT 1009-0	1978	(9447.00)	1		-447	0	0	0	0
Nov-05	Retire Data Star Recorders	Feb-87	(9102.00)	1		-102	0	0	0	0
Nov-05	Retire Installed Data Ster REcorder Software Level #2	Mar-87	(3,780.00)	5		0	0	0	0	-3780
Nov-05	Retire Payroll & overheads for above install	1987	(750.00)	5		0	0	0	0	-750
Nov-05	Retire 500' 4/C #12 AWG Control Cable	Aug-90	(1,014.38)	5		0	0	0	0	-1014.38
Nov-05	Retire 50' 1/2 watt precision resistors	Aug-90	(1,142.10)	5		0	0	0	0	-1142.1
Nov-05	Retire 350' T&B Stakon Terminals	Aug-90	(41.39)	5		0	0	0	0	-41.39
Nov-05	Retire 69' Copper Wire	Aug-90	(86.45)	5		0	0	0	0	-86.45
Nov-05	Retire Cable Tie	Aug-90	(10.35)	5		0	0	0	0	-10.35
Nov-05	Retire Misc Parts	Aug-90	(17.55)	5		0	0	0	0	-17.55
Nov-05	Retire 'Bristol DPC 333010A computer	Aug-90	(52.76)	5		0	0	0	0	-52.76
Nov-05	Retire Bristol SLC 371140A Recorders	Aug-90	(4,230.71)	5		0	0	0	0	-4230.71
Nov-05	Retire Bristol Power Supply	Aug-90	(5,771.41)	5		0	0	0	0	-5771.41
Nov-05	Retire Labor to set up Bristol	Aug-90	(515.05)	5		0	0	0	0	-515.05
Dec-06	Retired used Auto Transformer 24/40 mva Magntek	1992	(2,355.00)	5		0	0	0	0	-2355
Jul-08	Retire Deadend Structure 3-arrestors & 6-bushings	1994	(200,032.04)	4		0	0	0	-200,032.04	0
Total Pre-97 PTF			(30,233.66)	5		0	0	0	0	-30233.66
			3,259,541.37			1,202,389.70	598,768.91	0	1,377,877.70	80,505.06

Date	Description	In Service	Value	Classification	PTF	Non-PTF	PTF XMFR	Non-PTF XMFR	Common	5
<u>Land</u>					1	2	3	4		
Nov-97	69kv Post Insulators		7,125.43	2	0	7125.43	0	0	0	0
Feb-98	Install Metering & Test Switches		8,836.13	5	0	0	0	0	8836.13	
Mar-98	Install Lightning Arrester #1 Auto		1,990.46	2	0	1990.46	0	0	0	0
Mar-98	Repl Autotransformer 69kv Disconnect Switches		14,416.88	2	0	14416.88	0	0	0	0
Apr-98	Additional charges for above		3,799.62	2	0	3799.62	0	0	0	0
Apr-98	Install new Ammeters on Auto #1 & Auto #2		3,414.14	5	0	0	0	0	3414.14	
May-98	40KA interrupting rated breaker w/disconnect switch		71,361.36	2	0	71361.36	0	0	0	0
Nov-98	Voltage Potential Transformer		6,864.00	5	0	0	0	0	6864	
May-99	Southern States TA-OC 69kv 1200A Switch		19,419.24	2	0	19419.24	0	0	0	0
Dec-99	UV Relay installed		605.13	2	0	605.13	0	0	0	0
Mar-00	Modifications for 3rd 69kv line to River St S/S		162,000.94	2	0	162000.94	0	0	0	0
Apr-00	Dead Station Tripping Scheme		2,212.64	5	0	0	0	0	2212.64	
Aug-00	Replace 02 line ground relays		7,085.89	2	0	7085.89	0	0	0	0
Aug-00	Additional charges for modifications for 3rd line		9,717.74	2	0	9717.74	0	0	0	0
Oct-02	Replace #5 Bushing on 7A1 Oil Circuit Breaker		7,705.53	2	0	7705.53	0	0	0	0
Nov-02	Install Spare PT s/n 1024577		26,749.83	2	0	26749.83	0	0	0	0
Nov-02	Purchase spare PT JVZ350VT 350/600 s/n 1890057484		9,479.40	2	0	9479.40	0	0	0	0
Feb-03	Installation cost for Spare Bushing #5 (C-9293)		7,268.29	2	0	7268.29	0	0	0	0
Mar-03	Cable Trenches and Conduit for new Control House		95,020.03	5	0	0	0	0	95020.03	
Mar-03	Installation of cable trench for new Control House		113,635.68	5	0	0	0	0	113635.68	
Nov-05	Retire UV Relay Installed	Dec-99	(605.13)	2	0	-605.13	0	0	0	0
Nov-05	Retire Dead Station Tripping Scheme	Apr-00	(2,212.64)	5	0	0	0	0	-2212.64	
Nov-05	Retire Replace 02 line ground relays	Aug-00	(7,085.89)	2	0	-7085.89	0	0	0	0
Dec-06	Repl Autotransformer 69kv Disconnect Switches	1997	(14,416.88)	2	0.00	-14,416.88	0.00	0.00	0.00	
Dec-06	Repl Autotransformer 69kv Disconnect Switches additional chgs	1997	(3,799.62)	2	0	-3799.62	0	0	0	
Total POST-96 PTF			\$550,588.20		\$0.00	\$322,818.22	\$0.00	\$0.00	\$227,769.98	
Jan-04	Replace 69Kv Pin & Cap Insulator		529.89	2	0	529.89	0	0	0	0
Nov-05	FGE Control House Project (PTF)(See page 4 for detail)		438,483.13	1	438483.13	0	0	0	0.00	
Nov-05	FGE Control House Project (Non-PTF) (See page 5 for detail)		574,504.78	2	0	574504.78	0	0	0.00	
Dec-06	#1 AutoTransformer Install 169 grd oper 69kv airbrake switch		21,720.43	2	0	21720.43	0	0	0.00	
Dec-06	Purchase new Spare Auto Transformer 60/80/100MVA		959,517.11	4	0	0	0	959517.11	0.00	
Dec-06	Foundation for Spare Auto Transformer		31,222.40	4	0	0	0	31222.4	0.00	
Aug-07	Purchase & Install Battery Monitoring System - 115KV		11,450.47	1	11450.47	0	0	0	0.00	
Aug-07	Purchase & Install Battery Monitoring System - 69kv		11,450.48	2	0	11450.48	0	0	0.00	
Sep-07	Installation of Yard Lighting (PTF) (See page 6 for detail)		21,239.46	1	21239.46	0	0	0	0.00	
Sep-07	Installation of Yard Lighting (Non-PTF) (See page 6 for detail)		21,239.41	2	0	21239.41	0	0	0.00	
Nov-07	Labor Cost to install replacement line back-up relays - 115kv	2006	18,753.78	1	18753.78	0	0	0	0.00	
Dec-07	Labor Cost to install replacement line back-up relays - 69kv	2006	18,753.78	2	0	18753.78	0	0	0.00	
Oct-08	Labor and Materials to Install anchors & guys to support buss work 69kv		5,870.49	2	0	5870.49	0	0	0.00	
	Labor and Materials to upgrade and withstand additional load related to NGrid									
Mar-10	conductor replacement		29,891.16	1	29891.16	0	0	0	0.00	
Mar-10	Capacitor Voltage Transformer 115kv		18,731.61	1	18731.61	0	0	0	0.00	
Jul-11	Electric Plant Acquisition Adjustment		<u>\$122,600.09</u>	5	0	0	0	0	<u>122,600.09</u>	
Total Post-03 PTF			\$2,305,958.47		\$538,549.61	\$654,069.26	\$0.00	\$990,739.51	\$122,600.09	
PTF			1,740,939.31	\$	6,116,088.04	\$ 1,740,939.31	\$ 1,575,656.39	\$ -	\$ 2,368,617.21	\$ 430,875.13
non-PTF			1,575,656.39			52.49%	47.51%			
PTF Ratio			0.5249							
					Pre-97 PTF	1,202,390		POST-96 PTF	-	
					XFRM Pre-97 PTF	-		XFRM POST-96 PTF	-	
					COMMON Pre-97 PTF	<u>42,259</u>		COMMON POST-96 PTF	<u>119,560</u>	
					Total Pre-97PTF	<u>1,244,648</u>		Total POST-96 PTF	<u>119,560</u>	
					POST-03 PTF	538,550				
					XFRM POST-03 PTF	-				
					COMMON POST-03 PTF	<u>64,355</u>				
					Total POST-03 PTF	<u>602,905</u>				

Fitchburg Gas and Electric Light Company
Detail of 2005 Control House Project

Workpaper 1
Page 4

Date	Description	Value	Classification
Nov-05	115 kv portion of control house		
Nov-05	ABB & Relaying portion Control House	\$65,060.87	1
Nov-05	Control Building w/12 relay panels	\$61,811.68	1
Nov-05	Detention Crane Charges	\$400.00	1
Nov-05	Heating element kit for Sun HVAC unit	\$65.15	1
Nov-05	RF45 8 Wire Modular Adapter	\$34.90	1
Nov-05	Router configuration	\$291.00	1
Nov-05	Construction overheads on above	\$38,299.08	1
Nov-05	115 kv portion SCADA Equipment		
Nov-05	ABB & Relaying portion Control House	\$2,439.13	1
Nov-05	Control Building w/12 relay panels	\$2,317.32	1
Nov-05	PowerEdge Server 600SC	\$1,061.95	1
Nov-05	XP Software	\$178.85	1
Nov-05	1kVA/800W Utility Inverter	\$632.00	1
Nov-05	Cisco Modem Router s/n SFHK072621U0	\$1,180.02	1
Nov-05	Cisco Modem Router s/n SFHK072621U0	\$1,180.02	1
Nov-05	Port 4 Wire WanInterface	\$540.00	1
Nov-05	Port 4 Wire WanInterface	\$581.78	1
Nov-05	DSU/CSUModule	\$729.95	1
Nov-05	TG5700 RTU	\$3,045.00	1
Nov-05	ESCA License	\$5,200.00	1
Nov-05	Misc Electrical Materials	\$18.22	1
Nov-05	Postage Charges	\$30.79	1
Nov-05	PC Modem, Termination Card, & Cable	\$195.30	1
Nov-05	Router configuration	\$291.00	1
Nov-05	Sundry Cash	(\$2,982.92)	1
Nov-05	Construction overheads	\$7,527.03	1
Nov-05	115 kv portion Installation of Control House		
Nov-05	Fuses	\$724.42	1
Nov-05	Cutouts	\$1,256.70	1
Nov-05	Bussman NTN-R30 Neutral	\$168.70	1
Nov-05	Labor	\$130,350.95	1
Nov-05	SWC Engineering Services	\$75.00	1
Nov-05	Construction Overheads	\$107,747.46	1
Nov-05	115 kv portion		
Nov-05	Switching - Company Labor	\$6,245.00	1
Nov-05	115 kv portion		
Nov-05	Witness factory testing	\$1,676.13	1
Nov-05	115 kv portion Installation of Control House		
Nov-05	Company Labor	\$97.92	1
Nov-05	115 kv portion Installation of Control House		
Nov-05	Late charges	\$12.73	1
Nov-05	Control House (PTF)	\$438,483.13	

Fitchburg Gas and Electric Light Company
Detail of 2005 Control House Project

Workpaper 1
Page 5

Date	Description	Value	Classification
Nov-05	69 kv portion of control house purchase		
Nov-05	Detention Crane Charges	\$400.00	2
Nov-05	ABB & Relaying portion Control House	\$65,060.87	2
Nov-05	Control Building w/12 relay panels	\$61,811.68	2
Nov-05	Control Building	\$128,258.00	2
Nov-05	Heating element kit for Sun HVAC unit	\$65.15	2
Nov-05	RF45 8 Wire Modular Adapter	\$34.91	2
Nov-05	12 foot Wall Mount Enclosure (qty 2)	\$74.72	2
Nov-05	6 Port Panel Insert (qty 2)	\$41.50	2
Nov-05	Camlite Connectors (qty 24)	\$263.76	2
Nov-05	PVC (qty 1000)	\$617.18	2
Nov-05	Cash Reimbursement - Pine Tree Power Portion	(\$20,157.00)	2
Nov-05	Construction Overheads	\$77,536.77	2
Nov-05	<u>69 kv portion of SCADA Equipment</u>		
Nov-05	PowerEdge Server 600SC	\$1,061.95	2
Nov-05	XP Software	\$178.84	2
Nov-05	ABB & Relaying portion Control House	\$2,439.13	2
Nov-05	1kVA/800W Utility Inverter	\$632.00	2
Nov-05	Control Building w/12 relay panels	\$2,317.32	2
Nov-05	Cisco Modem Router s/n SFHK072621U0	\$1,180.02	2
Nov-05	Port 4 Wire WanInterface	\$270.00	2
Nov-05	DSU/CSUModule	\$729.95	2
Nov-05	ESCA License	\$5,200.00	2
Nov-05	Port 4 Wire WanInterface	\$581.79	2
Nov-05	TG5700 RTU	\$3,045.00	2
Nov-05	Misc Electrical Materials	\$18.22	2
Nov-05	Postage Charges	\$30.80	2
Nov-05	PC Modem, Termination Card, & Cable	\$195.30	2
Nov-05	Police Detail	\$139.00	2
Nov-05	Construction overheads	\$6,715.20	2
Nov-05	<u>69 kv portion Installation of Control House, etc.</u>		
Nov-05	SW&C Engineering Services	\$75.00	2
Nov-05	current limiting fuses	\$197.81	2
Nov-05	fuses	\$353.66	2
Nov-05	Bussman NTN-R30 Neutral	\$168.70	2
Nov-05	fuse link	\$8.85	2
Nov-05	Labor	\$135,238.28	2
Nov-05	Misc Dumpster Charges	\$90.78	2
Nov-05	Cash Reimbursement - Pine Tree Power Portion	(\$13,250.00)	2
Nov-05	Construction Overheads	\$109,905.29	2
Nov-05	69 kv portion		
Nov-05	Switching - Company Labor	\$1,298.22	2
Nov-05	69 kv portion		
Nov-05	Witness factory testing	<u>\$1,676.13</u>	2
	Control House (Non-PTF)	<u>\$574,504.78</u>	
	Total Control House Project Cost	\$1,012,987.91	

Fitchburg Gas and Electric Light Company
Detail of Installation of Yard Lighting - 2007

Date	Description	Value	Classification
Sep-07	115 kv portion - Installation of Yard Lighting:		
Sep-07	Contract Labor	5,046.89	1
Sep-07	Company Labor & Transportation	157.89	1
Sep-07	2000 ft. 3C/#10 Tray Cable	1,035.00	1
Sep-07	Pipe, boxes, switches, breakers, marking tape	483.00	1
Sep-07	Other Materials - connections & hardware	43.13	1
Sep-07	8 - 400 watt HPS Floodlights	3,012.67	1
Sep-07	4 - light poles (plastic)	0.00	1
Sep-07	Circuit Breaker	3.55	1
Sep-07	Construction Overheads	<u>11,457.33</u>	1
	Yard Lighting (PTF)	21,239.46	
Sep-07	69 kv portion - Installation of Yard Lighting:		
Sep-07	Contract Labor	5,046.88	2
Sep-07	Company Labor & Transportation	157.88	2
Sep-07	2000 ft. 3C/#10 Tray Cable	1,035.00	2
Sep-07	Pipe, boxes, switches, breakers, marking tape	483.00	2
Sep-07	Other Materials - connections & hardware	43.12	2
Sep-07	8 - 400 watt HPS Floodlights	3,012.67	2
Sep-07	4 - light poles (plastic)	0.00	2
Sep-07	Circuit Breaker	3.54	2
Sep-07	Construction Overheads	<u>11,457.32</u>	2
	Yard Lighting (Non-PTF)	<u>21,239.41</u>	
	Total Yard Lighting Cost	42,478.87	

Date	Description	Value	Classification	PTF	Non-PTF	PTF XMFR	Non-PTF XMFR	Common
				1	2	3	4	5
Post 2005								
Est. 2012	Flagg Pond Substation - Modify J136N Line Protection	\$66,000	1	\$66,000	\$0	\$0	\$0	\$0
Est. 2012	Flagg Pond Substation - Modify CT Wiring/PTF	\$190,000	1	\$190,000	\$0	\$0	\$0	\$0
Est. 2012	Flagg Pond Substation - Modify CT Wiring/non-PTF	\$10,000	2	\$0	\$10,000	\$0	\$0	\$0
Est. 2012	I135N Line Relaying - Fitzwilliam Project	\$86,334	1	\$86,334	\$0	\$0	\$0	\$0
Est. 2012	Upgrade Flagg Pond 115 kV Ring Bus	\$2,650,000	1	\$2,650,000	\$0	\$0	\$0	\$0
Est. 2012	Purchase Spare 115 kV Breaker	<u>\$120,000</u>	2	<u>\$0</u>	<u>\$120,000</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>
Total		\$3,122,334		\$2,992,334	\$130,000	\$0	\$0	\$0
PTF Ratio (See page 3)								52.49%
PTF Estimated Additions								\$2,992,334

WORKPAPER 2
Fitchburg Gas and Electric Light Company
2011 Cost of Capital

	<i>Amount Outstanding 12/31/11</i>	<i>C.O.C.</i>	<i>Weight</i>	<i>Weighted Cost of Capital</i>
Common Stock Equity	\$52,533,397	11.64%	42.28%	4.92%
Preferred Stock	1,727,596	6.84%	1.39%	0.10%
Long Term Debt (include. due in 1 yr.)	70,000,000	6.99%	56.33%	3.94%
Total	\$124,260,993			8.96%

Common Equity

Common Stock	\$22,627,257
Retained Earnings	10,413,223
Capital Stock Expense	(1,507,083)
Misc. Paid in Capital	21,000,000
Total	\$52,533,397

Preferred Stock \$100 Par

Series	<i>Amount Outstanding 12/31/11</i>	<i>Annual Issuance Expense</i>	<i>Annual Dividend Expense</i>	<i>Total Annual Cost</i>	<i>Effective Cost %</i>
5.125%	\$786,100	\$45	\$40,339	\$40,384	5.14%
8.00%	969,600	91	77,660	77,752	8.02%
	\$1,755,700	\$136	\$117,999	\$118,135	6.73%
Less: Capital Stock Expense	5.125% \$8,828				
	8.00% 19,276				
Subtotal	\$28,104				
Total	1,727,596				6.84%

Long Term Debt

Series		<i>Amount Outstanding 12/31/11</i>	<i>Annual Issuance Expense</i>	<i>Annual Interest Expense</i>	<i>Total Annual Cost</i>	<i>Effective Cost %</i>
30 Year Note, due Nov 30, 2023	6.75%	19,000,000	10,671	1,282,500	1,293,171	6.81%
30 Year Note, due Jan 15, 2029	7.37%	12,000,000	3,279	884,400	887,679	7.40%
30 Year Note, due Jun 1, 2031	7.98%	14,000,000	11,857	1,117,200	1,129,057	8.06%
22 year Notes, due Oct 15, 2025	6.79%	10,000,000	7,851	679,000	686,851	6.87%
25 year Notes, due Dec 15, 2030	5.90%	15,000,000	9,221	885,000	894,221	5.96%
Total		\$70,000,000	\$42,879	\$4,848,100	\$4,890,979	6.99%

Workpaper 3
Fitchburg Gas and Electric Light Company
Accumulated Deferred Income Tax

		<u>2011</u>	
1. Account 281	Accumulated Deferred Income Taxes - Accelerated Amortization Property	\$	- FF1, Page 273.8k
2. Account 282	Accumulated Deferred Income Taxes - Other Property	\$	21,789,070 FF1, Page 275.2k
3. Account 283	Account 283 - Electric	\$	(2,322,290) FF1, Page 277.3k
4. Account 283	Less FAS 106 OPEB	\$	(1,347,720)
5. Account 283	Less FAS 158	\$	(7,494,194)
		\$	28,308,693 Worksheet 3, Line 8

Detail for Lines 4 and 5. Source: accounting records.

	<u>Electric</u>		<u>Gas</u>		<u>Total</u>
Def FIT FAS 158 SERP	\$ (300,855)		\$ (303,065)		\$ (603,919)
Def SIT FAS 158 SERP	\$ (82,203)		\$ (82,806)		\$ (165,009)
Def FIT FAS 158 Pension	\$ (3,849,988)		\$ (3,963,061)		\$ (7,813,048)
Def SIT FAS 158 Pension	\$ (863,122)		\$ (886,828)		\$ (1,749,950)
Def FIT FAS 158 PBOP	\$ (1,945,476)		\$ (1,987,115)		\$ (3,932,591)
Def SIT FAS 158 PBOP	\$ (452,551)		\$ (460,933)		\$ (913,484)
Total FAS 158	\$ (7,494,194)		\$ (7,683,808)		\$ (15,178,002)
Def FIT FAS 106 OPEB	\$ (1,142,666)		\$ (1,066,545)		\$ (2,209,211)
Def SIT FAS 106 OPEB	\$ (205,053)		\$ (246,657)		\$ (451,710)
Total FAS 106 OPEB	\$ (1,347,720)		\$ (1,313,202)		\$ (2,660,921)

Workpaper 4
Fitchburg Gas and Electric Light Company
Labor Allocator
2010 percentages applicable to 2011 costs

	Gas	Electric	Total
Salaries & Wages - Operation & Maintenance			
Production - Maint	\$ 42,140	\$ 42,140	
Production - Oper	169,446		169,446
Transmission - Maint		31,551	31,551
Transmission - Oper	45,745	44,049	89,794
Distribution - Maint	216,022	348,295	564,317
Distribution - Oper	690,650	547,381	1,238,031
Customer Accounting	52,787	71,083	123,870
Admin & General	-	-	-
Total - O&M Direct Labor	1,216,790	1,042,359	2,259,149
Construction			
Direct Payroll	263,618	444,242	707,860
Overhead Payroll	341,652	269,213	610,865
Total - Construction Direct Labor	605,271	713,455	1,318,725
Total Direct Labor	\$ 1,822,061	\$ 1,755,813	\$ 3,577,874
Labor Allocator	50.93%	49.07%	100.00%

Workpaper 5
Fitchburg Gas and Electric Light Company
Post-2003 Accumulated Deferred Income Tax

			<u>2011</u>	
Account 281	Accumulated Deferred Income Taxes - Accelerated Amortization Property	\$		- FF1, Page 273.8k
Account 282	Accumulated Deferred Income Taxes - Other Property	\$	<u>21,789,070</u>	FF1, Page 275.2k
	Total Accounts 281, 282	\$	21,789,070	
	Plant Allocation Factor		<u>8.6334%</u>	Worksheet 5, Line 16
	Transmission Allocated (Total Accounts 281, 282 * Plant Allocation Factor)	\$	<u>1,881,138</u>	
	Post-2003 PTF Transmission Plant Allocation Factor		6.4526%	Worksheet 5, Line 3 - Column 2
	Post-2003 PTF Accumulated Deferred Income Tax	\$	121,382	Worksheet 1, Line 6

Workpaper 6
Fitchburg Gas and Electric Light Company
Transmission Support Payment Accounts

	<u>2011</u>	
20-20-13-00-565-75-00	BECO HQII - TRANSMISSION	\$ 1,972 Worksheet 7, BECo HQ Phase II - AC in MA
20-20-13-00-565-76-00	NEP HQII - TRANSMISSION	\$ 28,272 Worksheet 7, NEP HQ Phase II - AC in MA

NEW ENGLAND HYDRO-TRANSMISSION CORPORATION
HYDRO-QUEBEC PHASE II
CHESTER SVC FACILITY

2011 ACTUAL CHESTER SVC COSTS	\$ 2,742,986

SUPPORTER

Fitchburg Gas and Electric Light Company

SUPPORTER
SHARE

0.4341%	\$ 11,907 (1)

(1) Worksheet 7, NEP Chester SVC.

FG&E's accounting records do not provide sufficient level of detail. Data provided by NEP.

Input Panel

Sheet: Input Panel

ISO-NE Tariff Billing
PTO Annual Transmission Revenue Requirements
per OATT Attachment F and NEPOOL Agreement Part 2, Section 6.3

Shading denotes an input

Submitted on:	14-May-12
Revenue Requirements for (year):	Calendar Year 2011
Rates Effective for the period: through:	June 2012 May 2013
Customer:	Holyoke Gas & Electric Department
Customer ID:	44
Network Load ID:	73
Customer's NABS Number:	18
Name of Participant responsible for customer's billing:	Brian C. Beauregard
DUNs number of Participant responsible for customer's billing:	08-465-0050

	Pre-97 Revenue Requirements	Post-96 Revenue Requirements
Total of Attachment F - Sections A through I =	1,043,351 (a)	567,964 (f)
Total of Attachment F - Section J - Support Revenue	0 (b)	0 (g)
Total of Attachment F - Section K - Support Expense	40,407 (c)	0 (h)
Total of Attachment F - Section (L through O)	(679) (d)	0 (i)
Sub Total - Sum (A through I) - J + K + (L through O)	1,083,079 (e)=(a)+(b)+(c)+(d)	567,964 (j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	N/A	987,454 (k)
Annual True-up (per Attachment C to Attachment F Implementation Rule)	94,001 (l)	59,984 (m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)	1,177,080 (n)=(e)+(l)	1,615,403 (o)=(j)+(k)+(m)
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements & Post-96 Revenue Requirements Subtotals, Forecasted Revenue Requirements and True-ups (including interest)		2,792,483 (p)=(n)+(o)

PTO
FERC Interest Calculation associated with Under / (Over)
Transmission Revenue Requirements of PTF Facilities

1 2011 Est. Transmission Revenue Requirements (as billed)	6/11-05/12	Appendix C	Pre 1997	Post 1996	
2 2011 Actual Annual RR			992,109	509,914	ATRR - Prior Year
3 True-up Over/(Under) (Line 1 - Line 2)			1,083,079	567,964	Input Panel Subtotals
			-90,970	-58,050	

PRE97
Post1996

Undercollection / (Overcollection)

90,970

\$58,050

Initial Billing Period	PRE97 Balance	POST 1996 Balance	FERC Monthly Interest Rate	PRE97 Interest	POST 1996 Interest
June 2011	\$ 90,970	58,050	0.27%	\$ 246	\$ 157
July 2011	\$ 91,216	58,207	0.27%	246	157
August 2011	\$ 91,216	58,207	0.28%	255	163
September 2011	\$ 91,216	58,207	0.27%	246	157
October 2011	\$ 91,964	58,684	0.28%	257	164
November 2011	\$ 91,964	58,684	0.27%	248	158
December 2011	\$ 91,964	58,684	0.28%	257	164
January 2012	\$ 92,727	59,171	0.28%	260	166
February 2012	\$ 92,727	59,171	0.26%	241	154
March 2012	\$ 92,727	59,171	0.28%	260	166
April 2012	\$ 93,487	59,656	0.27%	252	161
May 2012	\$ 93,487	59,656	0.28%	262	167
	Total Interest			\$ 3,031	\$ 1,934
	True-Up			90,969.94	\$58,050
	Total TU & Int			\$ 94,001	\$ 59,984

Holyoke Gas and Electric Department
Forecasted Transmission Revenue Requirements of PTF Facilities

POST-1996

Shading denotes an input

Line No.	I. FORECASTED TRANSMISSION REVENUE REQUIREMENTS	Period	Attachment F	HG&E	Reference
			Reference Section:		
1	Forecasted Transmission Plant Additions	2012	Appendix C	\$4,100,000	
2	Carrying Charge Factor		Appendix C	24.08%	
3	Total Forecasted Revenue Requirements (Lines 1*2)			<u>\$987,454</u>	
	II. CARRYING CHARGE FACTOR				
4	Investment Return and Income Taxes		(A)	\$147,523	Worksheet 1a, line 14
5	Depreciation Expense		(B)	\$44,277	Summary, line 15
6	Amortization of Loss on Reacquired Debt		(C)	\$16,416	Summary, line 16
7	Investment Tax Credit		(D)	\$0	Summary, line 17
8	Property Tax Expense		(E)	\$34,907	Summary, line 18
9	Payroll Tax Expense		(F)	\$1,519	Summary, line 19
10	Operation & Maintenance Expense		(G)	\$193,592	Summary, line 20
11	Administrative & General Expense		(H)	\$129,730	Summary, line 21
12	Total Expenses (Lines 4 thru 11)			\$567,964	
13	PTF Transmission Plant		(A)(1)(a)	<u>\$2,358,238</u>	Summary, line 1
14	Carrying Charge Factor (Lines 12/13)			<u>24.08%</u>	

Holyoke Gas & Electric Department
Annual Revenue Requirements of pre-1997 & post-1996 PTF
for costs as billed in 2011 06/11-05/12

Attachment F

Line No.	I. INVESTMENT BASE	Reference Section	Pre 1997	Post 1996	Reference
1	Transmission Plant	(A)(1)(a)	4,271,276	2,267,299	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	254,738	135,221	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	0	0	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		4,526,014	2,402,520	
5	Accumulated Depreciation	(A)(1)(d)	2,828,580	1,501,481	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	0	0	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	23,649	12,553	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	0	0	Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		1,721,083	913,592	
10	Prepayments	(A)(1)(h)	1,139,447	604,847	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	60,884	32,319	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	70,137	34,306	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		2,991,551	1,610,484	
II. REVENUE REQUIREMENTS					
14	Investment Return and Income Taxes	(A)	254,282	134,731	Worksheet 2
15	Depreciation Expense	(B)	76,345	40,526	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	23,649	12,553	Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)	0	0	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	62,483	33,167	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	1,524	809	Worksheet 4, line 17 column 5
20	Operation & Maintenance Expense	(G)	311,388	165,293	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	205,635	109,156	Worksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0	0	Worksheet 7
22a	Share of Seabrook Transmission Revenue Requirement		13,810	0	From MMWEC Analysis of Holyoke's % Share
23	Transmission Support Revenue	(J)	0	0	Worksheet 7
24	Transmission Support Expense	(K)	44,074	0	Worksheet 7
25	Transmission Related Expense from Generators	(L)	0	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	0	0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(636)	0	NEPOOL Sch 1: ST Through and Out Revenues (TOUT Sch 1)
28	Transmission Rents Received from Electric Property	(O)	(444)	0	Page 37 line 18b * Actual number of Transmission poles
29	Total Revenue Requirements (Line 14 thru 28)		992,109	456,235	

Shading denotes an input

		Attachment F		
		Reference	Holyoke	Reference
Line No.	I. INVESTMENT BASE	Section:		
1	Transmission Plant	(A)(1)(a)	4,271,276	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	308,411	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		4,579,687	
5	Accumulated Depreciation	(A)(1)(d)	2,907,273	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	0	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	29,733	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	0	Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		1,702,147	
10	Prepayments	(A)(1)(h)	1,292,477	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	75,641	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	78,252	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		3,148,517	
II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	267,624	Worksheet 2
15	Depreciation Expense	(B)	80,196	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	29,733	Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)	0	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	63,225	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	2,751	Worksheet 4, line 17 column 5
20	Operation & Maintenance Expense	(G)	350,637	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	234,969	Worksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7
22a	Share of Seabrook Transmission Revenue Requirement		14,216	From MMWEC Analysis of Holyoke's % Share
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	40,407	Worksheet 7
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(228)	NEPOOL Sch 1: ST Through and Out Revenues (T)
28	Transmission Rents Received from Electric Property	(O)	(451)	Page 37 line 18b * Actual number of Trans
29	Total Revenue Requirements (Line 14 thru 28)		1,083,079	

Shading denotes an input

		Attachment F		
		Reference	Holyoke	Reference
		Section:		
Line No.	I. INVESTMENT BASE			
1	Transmission Plant	(A)(1)(a)	2,358,238	Worksheet 3a, line 1 column 5
2	General Plant	(A)(1)(b)	170,279	Worksheet 3a, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3a, line 4 column 5
4	Total Plant (Lines 1+2+3)		2,528,517	
5	Accumulated Depreciation	(A)(1)(d)	1,605,149	Worksheet 3a, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	0	Worksheet 3a, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	16,416	Worksheet 3a, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	0	Worksheet 3a, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		939,784	
10	Prepayments	(A)(1)(h)	713,596	Worksheet 3a, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	41,763	Worksheet 3a, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	40,415	Worksheet 3a, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		1,735,558	
II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	147,523	Worksheet 2a
15	Depreciation Expense	(B)	44,277	Worksheet 4a, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	16,416	Worksheet 4a, line 4 column 5
17	Investment Tax Credit	(D)	0	Worksheet 4a, line 5 column 5
18	Property Tax Expense	(E)	34,907	Worksheet 4a, line 8 column 5
19	Payroll Tax Expense	(F)	1,519	Worksheet 4a, line 17 column 5
20	Operation & Maintenance Expense	(G)	193,592	Worksheet 4a, line 13 column 5
21	Administrative & General Expense	(H)	129,730	Worksheet 4a, line 16 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	0	Worksheet 7
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	0	
28	Transmission Rents Received from Electric Property	(O)	0	
29	Total Revenue Requirements (Line 14 thru 28)		567,964	

Holyoke Gas & Electric Department

Annual Revenue Requirements
for costs in 2011

Pre-1997

Shading denotes an input

	CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG TERM DEBT	\$ Not Applicable	#VALUE!		#VALUE!	
COMMON EQUITY		#VALUE!		#VALUE!	#VALUE!
TOTAL INVESTMENT RETURN	\$ n/a	#VALUE!		#VALUE!	#VALUE!

Cost of Capital Rate=

(a) Weighted Cost of Capital	=	<u>0.0850</u>	PROXY PER INTERPRETIVE GUIDANCE DOCUMENT FOR IMPLEMENTATION RULE SECTION II.A.2 FOR AN MTO PLUS 50 BASIS PTS ADDER FOR JOINING RTO					
(b) Federal Income Tax	=	$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv.} \cdot \text{Eq. AFUDC}}{(\text{Tax Credit} + \text{of Deprec. Exp.}) / \text{PTF Inv. Base}} \right)}{1} \right) \times \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}}$						
	=	$\left(\frac{0.0000 + \left(\frac{0 + 0}{3,148,517} \right)}{1} \right) \times \frac{0}{0}$						
	=	<u>0.0000000</u>						
(c) State Income Tax	=	$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv.} \cdot \text{Eq. AFUDC}}{(\text{Tax Credit} + \text{of Deprec. Exp.}) / \text{PTF Inv. Base}} \right)}{1} \right) + \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}} \times \text{State Income Tax Rate}$						
	=	$\left(\frac{0.0000 + \left(\frac{0 + 0}{3,148,517} \right)}{1} \right) + \frac{0.0000000}{0} \times 0$						
	=	<u>0.0000000</u>						
(a)+(b)+(c) Cost of Capital Rate	=	<u>0.0850000</u>						

	(PTF)	
INVESTMENT BASE	\$ 3,148,517	From Worksheet 1
x Cost of Capital Rate	0.0850000	
= Investment Return and Income Taxes	267,624	To Worksheet 1

Holyoke Gas & Electric Department

Annual Revenue Requirements
for costs in 2011
Post-1998

Shading denotes an input

	CAPITALIZATION 12/31/10	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG TERM DEBT	\$ Not Applicable	#VALUE!		#VALUE!	
COMMON EQUITY		#VALUE!		#VALUE!	
		#VALUE!		#VALUE!	#VALUE!
TOTAL INVESTMENT RETURN	\$ n/a	#VALUE!		#VALUE!	#VALUE!

Cost of Capital Rate=

(a) Weighted Cost of Capital	=	<u>0.085 to 0.095</u>	PROXY PER INTERPRETIVE GUIDANCE DOCUMENT FOR IMPLEMENTATION RULE SECTION II.A.2 FOR AN MTO PLUS 50 BASIS PTS ADDER FOR JOINING RTO AND 100 BASIS PTS ADDER FOR ALL PTF T IN SERVICE ON OR AFTER 1/1/04 provided inc				
(b) Federal Income Tax	=	$\left(\frac{R.O.E. + \left(\frac{PTF \text{ Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.}}{PTF \text{ Inv. Base}} \right)}{1} \right) \times \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}}$					
	=	$\left(\frac{0.0000 + \left(\frac{0 + 0}{3,148,517} \right)}{1} \right) \times \frac{0}{0}$					
	=	<u>0.0000000</u>					
(c) State Income Tax	=	$\left(\frac{R.O.E. + \left(\frac{PTF \text{ Inv. (Tax Credit) + Eq. AFUDC of Deprec. Exp.}}{PTF \text{ Inv. Base}} \right)}{1} \right) + \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}} \times \text{State Income Tax Rate}$					
	=	$\left(\frac{0.0000 + \left(\frac{0 + 0}{3,148,517} \right)}{1} \right) + \frac{0.0000000}{0} \times 0$					
	=	<u>0.0000000</u>					
(a)+(b)+(c) Cost of Capital Rate	=	<u>#VALUE!</u>					

	(PTF) prior 1/1/04		(PTF) on or after 1/1/04		(PTF) on or after 1/1/04	
INVESTMENT BASE	\$ 1,735,558	From Worksheet 1	1,735,558	From Worksheet 1	1,735,558	From Worksheet 1
% Allocated to respective period	0.30%		99.70%		0.00%	
PERIOD INVESTMENT BASE	5,186		1,730,373		0	
x Cost of Capital Rate	0.0850000		0.0850000	Not included in RSP	0.0950000	Included in RSP
= Investment Return and Income Taxes	441	To Worksheet 1	147,082	To Worksheet 1	0	To Worksheet 1

Holyoke Gas & Electric Department
Pre-1997

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
<u>Transmission Plant</u>						
1	8,549,783		8,549,783		4,271,276	Line 1, Worksheet 5
2	7,928,094	7.7868% (a)	617,345	49.9577%	308,411	Page 8B, line 30g less line 29 telecom
3			9,167,128		4,579,687	
4	0		0	49.9577%	0	None known
<u>Transmission Accumulated Depreciation</u>						
5	5,386,287		5,386,287	49.9577%	2,690,865	Page 8A, line 31g less Page 16, line 31g
6	5,563,038	7.7868% (a)	433,183	49.9577%	216,408	(Page 8B, line 30g less line 29 telecom) less
7			5,819,470		2,907,273	(Page 17, line 30g less line 29g telecom)
<u>Transmission Accumulated Deferred Taxes</u>						
8	0	8.2250% (c)	0	49.9577%	0	None known
9	0	8.2250% (c)	0	49.9577%	0	None known
10			0		0	
11	723,597	8.2250% (c)	59,516	49.9577%	29,733	Page 13, line 28d
<u>Other Regulatory Assets</u>						
12	0	7.7868% (a)	0	49.9577%	0	None known
13	0	8.2250% (c)	0	49.9577%	0	None known
14	0	8.2250% (c)	0	49.9577%	0	
15	0		0		0	
16	33,224,717	7.7868% (a)	2,587,142	49.9577%	1,292,477	Page 10, line 26c
17	1,840,851	8.2250% (a)	151,410	49.9577%	75,641	Page 14, line 16b
Per Guidance Document I. R. Section II.A.1 as well as Application of I. R. to MTO's						
18	<u>Cash Working Capital</u>					
19	Operation & Maintenance Expense					350,637
20	Administrative & General Expense					234,969
21	Transmission Support Expense					40,407
22	Subtotal (line 19+20+21)					626,013
23						0.125
24	Total (line 22 * line 23)					78,252

x 45 / 360

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
<u>Transmission Plant</u>						
1	8,549,783		8,549,783		2,358,238	Line 1, Worksheet 5
2	7,928,094	7.7868% (a)	617,345	27.5824%	170,279	Page 8B, line 30g less line 29 telecom
3			9,167,128		2,528,517	
4	0		0	27.5824%	0	None known
<u>Transmission Accumulated Depreciation</u>						
5	5,386,287		5,386,287	27.5824%	1,485,667	Page 8A, line 31g less Page 16, line 31g
6	5,563,038	7.7868% (a)	433,183	27.5824%	119,482	(Page 8B, line 30g less line 29 telecom) less
7			5,819,470		1,605,149	(Page 17, line 30g less line 29g telecom)
<u>Transmission Accumulated Deferred Taxes</u>						
8	0	8.2250% (c)	0	27.5824%	0	None known
9	0	8.2250% (c)	0	27.5824%	0	None known
10			0		0	
11	723,597	8.2250% (c)	59,516	27.5824%	16,416	Page 12, line 28b
<u>Other Regulatory Assets</u>						
12	0	7.7868% (a)	0	27.5824%	0	None known
13	0	8.2250% (c)	0	27.5824%	0	None known
14	0	8.2250% (c)	0	27.5824%	0	
15	0		0		0	
16	33,224,717	7.7868% (a)	2,587,142	27.5824%	713,596	Page 10, line 26c
17	1,840,851	8.2250% (a)	151,410	27.5824%	41,763	Page 14, line 16b
Per Guidance Document I. R. Section II.A.1 as well as Application of I. R. to MTO's						
18					193,592	Worksheet 41a, Line 20
19					129,730	Worksheet 41a, Line 21
20					0	Worksheet 41a, Line 24
21					323,322	
22					0.125	
23					40,415	x 45 / 360
24						

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

Holyoke Gas & Electric Department
Pre-1997

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Mass DTE AR Reference for col (1)
Depreciation Expense						
1	133,477		133,477	49.9577%	66,682	Page 16, line 31d
2	347,389	7.7868% (a)	27,050	49.9577%	13,514	Page 17, line 30d less line 29 Telecom
3			160,527		80,196	
4	723,597	8.2250% (c)	59,516	49.9577%	29,733	Page 13, line 28d
5	0	8.2250% (c)	0	49.9577%	0	None known
Property Taxes *						
6	119,596		119,596	49.9577%	59,747	See below
7	89,409	7.7868% (a)	6,962	49.9577%	3,478	
8			126,558		63,225	
Transmission Operation and Maintenance						
9	3,629,628		3,629,628	49.9577%	1,813,279	Page 40, line 50b
10	2,927,761		2,927,761	49.9577%	1,462,642	Page 40, line 38b
11	0		0	49.9577%	0	Page 40, line 34b
12	0		0		0	Page 40, line 35b, 40b only if include Support
13	701,867		701,867	49.9577%	350,637	
Transmission Administrative and General						
14	6,103,951					Page 42, line 7b less line 5b, less pg 41 line 56b telecom
15	432,807					Page 41, line 49b
16	0					Page 41, line 52b
17	88,129					G/L Acct 930-03 Public Goodwill less Fiber Optic Cable
18	5,583,015	7.7868% (a)	434,738	49.9577%	217,185	
19	432,807	8.2250% (c)	35,598	49.9577%	17,784	
20	0	8.2250% (c)	0	49.9577%	0	
21	0	8.2250% (c)	0	49.9577%	0	
22	6,015,822		470,336		234,969	
23	70,705	7.7868% (a)	5,506	49.9577%	2,751	Footnote (d)
Payroll Tax Expense						
(a) Worksheet 5 of 8, line 11						
(b) Worksheet 5 of 8, line 3						
(c) Worksheet 5 of 8, line 16						
(d) Payroll taxes						
Federal Unemployment	14,742	G/L Acct 926-05				
FICA/Medicare	55,963	G/L Acct 926-06				
MA Unemployment	0					
MA Universal Health	0					
Total	70,705	To Line 23				
* Property Taxes						
NBV Transmission Plant			3,163,498			Page 16, line 31g
NBV General Plant			2,384,986			Page 17, line 30g less line 29g telecom
Local property tax rate - 1st half			37.08			Page 3, line 9 of 2011 DPU State Return
Local property tax rate - 2nd half			38.53			Page 3, line 9 of 2011 DPU State Return

** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments.

Holyoke Gas & Electric Department
Post-1996

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Mass DTE AR Reference for col (1)
Depreciation Expense						
1	133,477		133,477	27.5824%	36,816	Page 16, line 31d
2	347,389	7.7868% (a)	27,050	27.5824%	7,461	Page 17, line 30d less line 29 Telecom
3			160,527		44,277	
4	723,597	8.2250% (c)	59,516	27.5824%	16,416	Page 13, line 28d
5	0	8.2250% (c)	0	27.5824%	0	None known
Property Taxes *						
6	119,596		119,596	27.5824%	32,987	See below
7	89,409	7.7868% (a)	6,962	27.5824%	1,920	
8			126,558		34,907	
Transmission Operation and Maintenance						
9	3,629,628		3,629,628	27.5824%	1,001,139	Page 40, line 50b
10	2,927,761		2,927,761	27.5824%	807,547	Page 40, line 38b
11	0		0	27.5824%	0	Page 40, line 34b
12					0	Page 40, line 35b, 40b Only if includes Support
13	701,867		701,867	27.5824%	193,592	
Transmission Administrative and General						
14	6,103,951					Page 42, line 7b less line 5b, less pg 41 line 56b telecom
15	432,807					Page 41, line 47b
16	0					Page 41, line 50b
17	88,129					GL Acct 930-03 Public Goodwill less in Lieu of Discounts & Fiber Optic Cable
18	5,583,015	7.7868% (a)	434,738	27.5824%	119,911	
19	432,807	8.2250% (c)	35,598	27.5824%	9,819	
20	0	8.2250% (c)	0	27.5824%	0	
21	0	8.2250% (c)	0	27.5824%	0	
22	6,015,822		470,336		129,730	
23	70,705	7.7868% (a)	5,506	27.5824%	1,519	Footnote (d)
Payroll Tax Expense						
(a) Worksheet 5 of 8, line 11						
(b) Worksheet 5 of 8, line 3						
(c) Worksheet 5 of 8, line 16						
(d) Payroll taxes						
Federal Unemployment	14,742	926-05				
FICA/Medicare	55,963	926-06				
MA Unemployment	0					
MA Universal Health	0					
Total	70,705	To Line 23				
* Property Taxes						
NBV Transmission Plant			3,163,496			Page 16, line 31g
NBV General Plant			2,364,996			Page 17, line 30g
Local property tax rate - 1st half			37.08			Page 3, line 9 of 2009 DPU State Return
Local property tax rate - 2nd half			38.53			Page 3, line 9 of 2009 DPU State Return

** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments.

Shading denotes an input

Line No.	Mass DTE AR Reference

PTF Transmission Plant Allocation Factor**Holyoke**

	Pre-1997	Post-1996	
1 PTF Transmission Investment	4,271,276	2,358,238	(50% of FERC Acct # 353 per Rule 8 after excluding transformer non-ptf cost, 100% of FERC Acct's 355 & 356 from page 8A, lines 24g, 26g, & 27g respectively)+ 100% from pg 8A lines 31c - 31d +31e+31f Page 8A, line 31g
2 Total Transmission Investment	8,549,783	8,549,783	
3 Percent Allocation (Line 1/Line 2)	49.9577%	27.5824%	

<1/1/04

>1/1/04

7,046

2,351,192

pg 8a lines

31c+31d+31e+31f

Transmission Wages and Salaries Allocation Factor

4 Direct Transmission Wages and Salaries	566,102		Page 40, line 33b, 35b, 36b, 35b, 45b, 46b Breakdown (see Below)
5 Affiliated Company Transmission Wages and Salaries	0		Worksheet 6 & 6a of 8
6 Total Transmission Wages and Salaries (Line 4 + Line 5)	566,102		
7 Total Wages and Salaries	8,078,550		Page 42, line 25 less telecom Wages
8 Administrative and General Wages and Salaries	808,545		Page 41, line 45b
9 Affiliated Company Wages and Salaries less A&G	0		Worksheet 6 & 6a of 8
10 Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	7,270,005		
11 Percent Allocation (Line 6/Line 10)	7.7868%		

Plant Allocation Factor

12 Total Transmission Investment	8,549,783		Line 2
13 plus Transmission-Related General Plant (Line 2 of Wkst. 3)	617,345		Worksheet 3, Line 2
14 = Revised Numerator (Line 12 + Line 13)	9,167,128		
15 Total Plant in Service	111,454,535		Page 8B, line 31g less line 15g, less line 29g telecom
16 Percent Allocation (Line 14 / Line 15)	8.2250%		

(Line #4) Breakdown of Transmission Expenses by FERC #

Expenses (*)	Labor (*)	Total from MDTE AR
560 15,684	334,048	349,712
562 19,606	130,675	150,281
563 -	-	-
566 -	18,992	18,992
570 92,250	31,049	123,299
571-00 7,102	48,672	55,776
571-01 1,143	2,666	3,809
Total	566,102	

(*) From General Ledger Trial Balance Report for December 31, 2011 Yr End

Affiliated Company Wages and Salaries

Shading denotes an input

Line		Holyoke
"Affiliated" Transmission Wages and Salaries #560 - 573		
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11 = 1 thru 10	Total Transmission	0
12 = Total "Affiliated" Wages and Salaries		0
Less "Affiliated" Administrative and General Salaries #920 - 935		
13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
21 = 13 thru 20		0
22 = 12 less 21 Total "Affiliated" less A&G		0

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	FERC Form 1	TOTAL	
			Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	332.(g); [332.1(g) for HWP]		1,032
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			658
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			7,381
	Comerford 115 kV Substation			
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	332.1(g); [332(g) for CL&P]		17,487
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 394 line	332(g)		1,311
	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			1,239
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		0
	345 kV Millstone-Manchester 310 line	330.1(n)		11,299
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
Total =			0	40,407

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

Holyoke Gas & Electric Department - 2012 Forecasted Transmission Projects In-Service

Primary Equipment Owner	Other Equipment Owner(s)	Projected In-Service Month/Year	Project	November 2011 Status	March 2012 Status	Substation ROW	Transmission ROW	Estimated Costs	Estimated % PTF	Estimated PTF In-Service Costs
Holyoke Gas & Electric Department		Dec-12	North Canal 44P Substation	Planned	Planned	Not Required	Not Required	\$13,000,000	32%	\$4,100,000

2010 Forecasted Transmission Plant Additions = \$4,100,000

Account/Description Date Transaction Type Work Order Job Vendor Projects/Grants	Reference	Debits	Credits	Balance
0030-30-930-930-03-1	PUBLIC GOODWILL			.00 *
1/31/11 FIBER OPTIC CABLE CONNECTION JE	000000000024284	108.34		
2/25/11 OPPORTUNITY LEVEL SPONSOR IN GREATER HOLYOKE YMCA	000000000024350	650.00		
2/25/11 SUMMER CONCERT SERIES IN HOLYOKE ROTARY FOUNDATION INC	000000000024350	650.00		
2/25/11 1/2 PG AD CIRCUS PROG IN MELHA SHRINERS	000000000024350	113.75		
2/28/11 FIBER OPTIC CABLE CONNECTION JE	000000000024615	108.34		
3/31/11 CHIEF SCOTT RETIREMENT IN MISC VENDOR	000000000024684	227.50		
3/31/11 FIBER OPTIC CABLE CONNECTION JE	000000000024736	108.34		
3/31/11 3-40-11 MISC PP EXPENSE MARCH JE	000000000024822	650.00		
4/26/11 COLLEEN FLOAT-AMBASSADOR'S AWARD IN ST PATRICK'S COMMITTEE HOLYOKE INC	000000000024887	4,875.00		
4/30/11 4-47-11 MISC PREPAID APRIL JE	000000000025084	650.00		
4/30/11 FIBER OPTIC CABLE CONNECTION JE	000000000025107	108.34		
5/04/11 PETTY CASH REIMBURSED IN PETTY CASH	000000000024953	195.00		
5/31/11 FIBER OPTIC CABLE CONNECTION JE	000000000025241	108.34		
5/31/11 5-38-11 MISC PREPAID MAY JE	000000000025268	650.00		
6/06/11 O#1019527 IN CHOICE INDUSTRIAL SOLUTIONS INC	000000000025224	91.39		
6/08/11 HOLE SPONSORSHIP IN SUNSHINE VILLAGE	000000000025208	65.00		
6/27/11 SPONSORSHIP-FIREWORKS IN GREATER HOLYOKE CHAMBER OF	000000000025342	12,025.00		
6/27/11 2 HRS @ HOLYOKE FIREWORKS IN MISC VENDOR	000000000025342	650.00		
6/27/11 3 HRS RENTAL-HCC FIREWORKS IN MISC VENDOR	000000000025342	2,366.00		
6/29/11 JESTER HAT IN NEPM-ASI /AMDA ENTERPRISES INC	000000000025507	81.87		
6/29/11 LED BALLOONS IN NEPM-ASI /AMDA ENTERPRISES INC	000000000025507	553.00		
6/29/11 BALLOONS IN NEPM-ASI /AMDA ENTERPRISES INC	000000000025507	39.95		
6/29/11 BALLOONS IN NEPM-ASI /AMDA ENTERPRISES INC	000000000025507	506.74		
6/29/11 GLOW STICKS IN NEPM-ASI /AMDA ENTERPRISES INC	000000000025507	386.76		

Account/Description Date Transaction Type Work Order Job Vendor Projects/Grants	Reference	Debits	Credits	Balance
0030-30-930-930-03-1	PUBLIC GOODWILL			.00 *
6/29/11 FIBER OPTIC WANDS IN NEPM-ASI /AMDA ENTERPRISES INC	000000000025507	515.22		
6/30/11 6-54-11 MISC PREPAID EXPENSE JUNE JE	000000000025493	650.00		
6/30/11 FIBER OPTIC CABLE CONNECTION JE	000000000025517	108.34		
7/25/11 SPONSORSHIP-E MTN COUNTRY CLUB IN JOHN DINAPOLI GOLF TOURNAMENT	000000000025508	650.00		
7/25/11 EAGLE SPONSORSHIP-WYCKOFF CC IN BLESSED SACRAMENT PTG	000000000025508	650.00		
7/25/11 SILVER SPONSORSHIP-THOMPSON-WYCKOFF IN BOYS & GIRLS CLUB OF GREATER	000000000025508	975.00		
7/25/11 TIME WRESTLING SPONSORSHIP IN BOYS & GIRLS CLUB OF GREATER	000000000025508	325.00		
7/25/11 RECEPTION-GOLD SPONSOR IN LOOMIS COMMUNITIES THE	000000000025508	325.00		
7/25/11 RED LEVEL TEE SPONSORSHIP IN JERICHO	000000000025508	325.00		
7/25/11 BOLD LEVEL SPONSORSHIP IN GIRLS INC OF HOLYOKE	000000000025508	650.00		
7/22/11 MISC RECEIVABLES JE	000000000025496		65.90	
7/25/11 SPONSORSHIP-CHESTNUT/VETERANS PK IN MA INTERNATIONAL FESTIVAL OF ARTS	000000000025508	325.00		
7/25/11 DISTRIB ON PROMO MATL-FIREWORKS IN HOLYOKE MERRY-GO-ROUND	000000000025508	325.00		
7/25/11 1/4 PAGE AD IN SCHOOL NEWSPAPER IN THE HOLYOKE HERALD	000000000025508	97.50		
7/25/11 SPONSORSHIP-SCHOOL NEWSPAPER IN THE HOLYOKE HERALD	000000000025508	97.50		
7/25/11 FULL PAGE AD IN FRIENDS OF HOLYOKE HIGH FOOTBALL	000000000025508	195.00		
7/25/11 AD IN SISTERHOOD CALENDAR IN SISTERHOOD RODPHEY SHOLOM	000000000025508	22.75		
7/25/11 SPONSORSHIP-DOMINICAN REPUBLIC IN NEW HORIZONS COMMUNITY CENTER	000000000025508	325.00		
7/26/11 SPONSORSHIP-SOCCER IN HOLYOKE YOUTH SOCCER LEAGUE	000000000025526	162.50		
7/31/11 7-54-11 MISC PREPAID JULY JE	000000000025684	650.00		
7/31/11 FIBER OPTIC CABLE CONNECTION JE	000000000025736	108.34		
8/10/11 PETTY CASH REIMB IN PETTY CASH	000000000025635	131.80		
8/18/11 FULL PG AD PROG BOOK EOY IN HOMEWORK HOUSE INC	000000000025701	162.50		
8/03/11 PROGRAM BOOK IN HOLYOKE CIVIC SYMPHONY	000000000025586	162.50		

Account/Description Date Transaction Type Work Order Job Vendor Projects/Grants	Reference	Debits	Credits	Balance
0030-30-930-930-03-1	PUBLIC GOODWILL			.00 *
8/13/11 8/11 ISLAND-U PK IN MOUNTAIN VIEW LANDSCAPES & LAWN CARE	000000000025742	195.00		
8/18/11 SPONSORSHIP SPFLD CC IN HCC FOUNDATION	000000000025701	780.00		
8/18/11 SPONSORSHIP IN HOLYOKE POLICE RELIEF ASSOCIATION	000000000025701	32.50		
8/18/11 SPONSORSHIP IN LT DANNY BOYLE MEMORIAL RUN	000000000025701	487.50		
8/18/11 AMIGO LEVEL SPONSORSHIP-PICNIC IN MASS LATINO CHAMBER OF COMMERCE	000000000025701	195.00		
8/18/11 CANALWALK-FIRST LIGHT IN NUEVA ESPERANZA	000000000025701	325.00		
8/18/11 SPONSORSHIP IN PASSPORT HOLYOKE INC	000000000025701	65.00		
8/18/11 SPONSORSHIP-HCC IN PJ SHANAHAN BENEFIT	000000000025701	325.00		
8/18/11 SPONSORSHIP-SUMMER EMPLOY IN REG EMPLOYMENT BOARD OF HAMPDEN COU	000000000025701	97.50		
8/18/11 SPONSORSHIP-SPFLD CC IN SISTERS OF ST JOSEPH	000000000025701	650.00		
8/18/11 SPONSORSHIP-GREEN FLAG IN VALLEY HEALTH SYSTEMS, INC	000000000025701	325.00		
8/18/11 SPONSORSHIP-INDUCT/MORG/ETC IN VOLLEYBALL HALL OF FAME	000000000025701	3,250.00		
8/31/11 FIBER OPTIC CABLE CONNECTION JE	000000000025948	108.34		
7/06/11 C#83070 IN TAYLOR RENTAL	000000000026112	197.60		
8/19/11 C#241978 IN NEPM-ASI /AMDA ENTERPRISES INC	000000000026112	1,394.25		
8/25/11 CONF DES/LOG IN YOUR FRIEND IN SPRINGFIELD	000000000026112	1,186.25		
8/30/11 CO#523 AG#250837 IN MARCOTTE FORD SALES INC	000000000026112	88.13		
9/08/11 8/25-9/8 SERV IN YOUR FRIEND IN SPRINGFIELD	000000000026112	975.00		
9/28/11 9/9-28 INNOV CONF IN YOUR FRIEND IN SPRINGFIELD	000000000026112	2,860.00		
9/30/11 FIBER OPTIC CABLE CONNECTION JE	000000000026178	108.34		
10/05/11 PETTY CASH REIMBURSED IN PETTY CASH	000000000026059	274.54		
10/13/11 ANNUAL BALL PROG AD IN HOLYOKE FIREMEN'S AID ASSOCIATION	000000000026102	65.00		
10/13/11 10/14/11 IDEA MILL CONFERENCE IN AUDIO PROMEDIA	000000000026102	2,177.50		
10/14/11 IDEAMILL-WISTARIAH IN LOG CABIN BANQUET & MEETING HOUSE	000000000026245	1,322.16		

Account/Description Date Transaction Type Work Order Job Vendor Projects/Grants	Reference	Debits	Credits	Balance
0030-30-930-930-03-1	PUBLIC GOODWILL			.00 *
10/17/11 MAINT SERVICES IN OPEN SQUARE PROPERTIES LLC	000000000026245	1,267.50		
10/20/11 RENTAL CAR REIMB IN MISC VENDOR	000000000026160	57.32		
10/20/11 RENTAL CAR & FUEL REIMB IN MISC VENDOR	000000000026160	90.12		
10/20/11 MUSIC ROOM -RECEPTION 10/14/11 IN WISTARIAHURST MUSEUM	000000000026160	325.00		
10/20/11 2 HR PIANO PERF 10/14 WIST MUS IN HOLYOKE CIVIC SYMPHONY	000000000026160	195.00		
10/20/11 9/29-10/14IDEAMILL IN YOUR FRIEND IN SPRINGFIELD	000000000026253	3,835.00		
10/20/11 NAME BADGE INSERTS IN MARCUS COMPANY INC	000000000026245	140.54		
10/25/11 XXX8-11004 IN AMERICAN EXPRESS-NEWARK	000000000026245	4,831.45		
10/27/11 VIDEO PROD IDEAMILL IN SCOTT HANCOCK	000000000026245	1,755.00		
10/31/11 FIBER OPTIC CABLE CONNECTION JE	000000000026420	108.34		
11/02/11 SPONSORSHIP-FIELD HOCKEY TOURN IN CITY OF HOLYOKE PARKS & RECREATION	000000000026237	325.00		
11/02/11 MISC EXP-IDEAMILL IN MISC VENDOR	000000000026237	442.01		
11/02/11 SPONSORSHIP-2011 SEASON IN HOLYOKE HIGH SOCCER BOOSTER CLUB	000000000026237	325.00		
11/02/11 SPONSORSHIP-HOLIDAY PARTY IN HOLYOKE POLICE SPECIAL EVENTS	000000000026237	975.00		
11/02/11 IDEAMILL-MISC EXP 10/14 IN MISC VENDOR	000000000026237	65.00		
11/02/11 2011 AUTUMN HORSE SHOW IN THE THERAPEUTIC EQUESTRIAN CENTER	000000000026237	227.50		
11/02/11 ENERGY CONN CONF SPONSORSHIP IN UNIVERSITY OF MA-CLEAN ENERGY CONN	000000000026237	650.00		
11/02/11 EXP-SIGNAGE & TRANSPORT IN YOUR FRIEND IN SPRINGFIELD	000000000026237	433.63		
11/02/11 GASOLINE FOR TRANSPORT IN MISC VENDOR	000000000026237	35.40		
11/28/11 SPONSORSHIP-APRIL 2012 IN CREDIT FOR LIFE	000000000026439	162.50		
11/28/11 BENEFACTOR SPONSORSHIP IN HOSPICE LIFE CARE	000000000026439	650.00		
11/28/11 SPONSORSHIP-COMMUNITY FAIR IN NEW HORIZONS COMMUNITY CENTER	000000000026439	162.50		
11/28/11 ANNUAL SPONSORSHIP IN SOUTHAMPTON YOUTH ATHLETICS ASSOC	000000000026439	97.50		
11/30/11 10/15-11/22 IDEA MILL CONF IN YOUR FRIEND IN SPRINGFIELD	000000000026454	1,787.50		

Account/Description Date Transaction Type Work Order Job Vendor Projects/Grants	Reference	Debits	Credits	Balance
0030-30-930-930-03-1	PUBLIC GOODWILL			.00 *
11/30/11 FIBER OPTIC CABLE CONNECTION JE	000000000026482	108.34		
12/06/11 PETTY CASH REIMBURSED IN PETTY CASH	000000000026511	130.00		
12/07/11 IDEAMILL 10/14 OPEN SQ IN CONKLIN OFFICE FURNITURE	000000000026532	1,719.25		
11/07/11 2011-12 LEADER IN GREATER HOLYOKE CHAMBER OF	000000000026805	6,792.50		
12/05/11 SPONSORSHIP-BASEBALL IN HOLYOKE COMMUNITY COLLEGE	000000000026499	650.00		
12/23/11 FULL PAGE AD-SHSNI IN BOYS & GIRLS CLUB OF GREATER	000000000026664	130.00		
12/31/11 FIBER OPTIC CABLE CONNECTION JE	000000000026750	108.34		
12/31/11 IN KIND CAREERPOINT JE	000000000026750	205.84		
1/26/12 SPONSORSHIP-11/9/11 WKSHOP IN UNIVERSITY OF MA-CLEAN ENERGY CONN	000000000026802	904.54		
Totals		81,084.84	65.90	81,018.94 81,018.94 *
0030-30-930-930-03-2	PUBLIC GOODWILL LABOR			.00 *
1/31/11 1-25-11 ELEC GUILD P/R JANUARY JE	000000000021875	70.80		
3/31/11 3-11-11 ELEC P/R MARCH JE	000000000024728	247.94		
3/31/11 3-29-11 ELECTRIC GUILD P/R ACCRUED JE	000000000024801	598.18		
4/01/11 3-29-11 ELECTRIC GUILD P/R ACCRUED JE	000000000024929		598.18	
4/30/11 4-19-11 ELEC GUILD P/R APRIL JE	000000000024957	771.60		
4/30/11 4-45-11 ELEC MULTI APRIL JE	000000000025073	37.77		
5/31/11 5-16-11 ELEC GUILD P/R MAY JE	000000000025193	72.94		
5/31/11 5-30-11 ELEC P/R ACCRUED JE	000000000025254	608.79		
5/31/11 5-44-11 ELEC MULTI MAY P/R JE	000000000025275	75.54		
5/31/11 5-46-11 ELEC MULTI MAY P/R JE	000000000025287	91.73		
6/01/11 5-46-11 ELEC MULTI MAY P/R JE	000000000025378		91.73	
6/01/11 5-30-11 ELEC P/R ACCRUED JE	000000000025384		608.79	

Less Fiber OPTIC
 Cable Connection
 (circled items)

81,018.94
 -1,300.08
 79,718.86

Account/Description Date Transaction Type Work Order Job Vendor Projects/Grants	Reference	Debits	Credits	Balance
0030-30-930-930-03-2	PUBLIC GOODWILL LABOR			.00 *
6/30/11 6-23-11 ELEC MULTI JUNE JE	000000000025419	75.54		
6/30/11 6-10-11 ELEC GUILD P/R JUNE JE	000000000025418	1,551.74		
6/30/11 6-37-11 ELEC MULTI P/R ACCRUED JE	000000000025442	26.98		
6/30/11 6-50-11 ELECTRIC GUILD P/R ACCRUED JE	000000000025477	179.60		
7/01/11 6-50-11 ELECTRIC GUILD P/R ACCRUED JE	000000000025554		179.60	
7/01/11 6-37-11 ELEC MULTI P/R ACCRUED JE	000000000025559		26.98	
7/31/11 7-19-11 ELEC P/R GUILD JULY JE	000000000025664	794.96		
7/31/11 7-46-11 ELECTRIC GUILD P/R ACCRUED JE	000000000025697	82.72		
8/01/11 7-46-11 ELECTRIC GUILD P/R ACCRUED JE	000000000025812		82.72	
8/31/11 8-20-11 ELEC MULTI P/R AUGUST JE	000000000025879	86.54		
8/31/11 8-17-11 ELEC GUILD P/R AUGUST JE	000000000025874	648.62		
8/31/11 8-36-11 ELECTRIC GUILD P/R AUGUST JE	000000000025908	227.61		
9/01/11 8-36-11 ELECTRIC GUILD P/R AUGUST JE	000000000026019		227.61	
9/30/11 9-15-11 SEPTEMBER GAS P/R JE	000000000026042	2,577.65		
9/30/11 9-13-11 ELEC GUILD P/R SEPTEMBER JE	000000000026039	289.68		
9/30/11 9-40-11 ELECTRIC P/R ACCRUED JE	000000000026154	33.54		
10/01/11 9-40-11 ELECTRIC P/R ACCRUED JE	000000000026219		33.54	
10/31/11 10-20-11 ELECTRIC GUILD P/R OCTOBER JE	000000000026291	320.84		
10/31/11 10-31-11 ELECTRIC GUILD P/R ACCRUED JE	000000000026354	167.95		
10/31/11 10-57-11 ELEC MULTI OCTOBER JE	000000000026396	127.38		
11/01/11 10-31-11 ELECTRIC GUILD P/R ACCRUED JE	000000000026464		167.95	
11/30/11 11-26-11 ELEC GUILD P/R NOVEMBER JE	000000000026531	146.96		
11/30/11 11-37-11 NOVEMBER HAS P/R ACCRUED JE	000000000026625	1,408.83		
12/01/11 11-37-11 NOVEMBER HAS P/R ACCRUED JE	000000000026732		1,408.83	

Account/Description			Reference	Debits	Credits	Balance
Date	Transaction					
Type	Work Order	Job	Vendor			
Projects/Grants						
0030-30-930-930-03-2			PUBLIC GOODWILL LABOR			.00 *
12/31/11	12-20-11	ELEC GUILD P/R DECEMBER	000000000026744	416.16		
JE						
12/31/11	12-39-11	ELEC MULTI DECEMBER	000000000026754	97.25		
JE						
12/31/11	12-56-11	GAS P/R DECEMBER	000000000026770	1,095.76		
JE						
** PUBLIC GOODWILL LABOR			Totals	12,931.60	3,425.93	9,505.67
						9,505.67 *
Fund ELECTRIC			Totals	94,016.44	3,491.83	90,524.61

Less GAS P/R
December

-\$1095.76
\$8,409.91 Labor

PREPARED 5/02/12 , 13:57:03
PROGRAM MADG125
Holyoke Gas & Electric Department

Trial Balance

Page 2

Account	Description	Debit	Credit
0030-30-926-926-05-1	UNEMPLOYMENT BENEFIT CLAIMS	14,742.00	.00
0030-30-926-926-06-1	FICA MEDICARE TAX	55,963.08	.00
ELECTRIC		<u>70,705.08</u>	<u>.00</u>
All Fund Totals		=====70,705.08=====	=====.00=====

PREPARED 5/02/12 , 8:47:37
PROGRAM MADG125
Holyoke Gas & Electric Department

Trial Balance

Page 2

Account	Description	Debit	Credit
0030-30-560-560-00-1	TRANS OPER SUPV & ENG EXPENSES	15,663.76	.00
0030-30-560-560-00-2	TRANS OPER SUPV & ENG LABOR	334,048.49	.00
0030-30-562-562-00-1	TRANSMISSION STATION EXPENSES	19,605.69	.00
0030-30-562-562-00-2	TRANSMISSION STATION LABOR	130,675.08	.00
ELECTRIC		499,993.02	.00
All Fund Totals		499,993.02	.00

PREPARED 5/02/12 , 8:48:54
PROGRAM MADG125
Holyoke Gas & Electric Department

Trial Balance

Page 2

Account	Description	Debit	Credit
0030-30-570-570-00-1	MAINT TRANSMISSION PLANT EXPENSE	92,250.09	.00
0030-30-570-570-00-2	MAINT TRANSMISSION PLANT LABOR	31,048.73	.00
0030-30-571-571-00-1	MAINT OVERHEAD LINES EXPENSE	7,102.37	.00
0030-30-571-571-00-2	MAINT OVERHEAD LINES LABOR	48,672.15	.00
0030-30-571-571-01-1	TRANS/MAINT CLEARANCE EXPENSE	1,142.92	.00
0030-30-571-571-01-2	TRANS/MAINT CLEARANCE LABOR	2,665.64	.00
ELECTRIC		182,881.90	.00
All Fund Totals		182,881.90	.00

PREPARED 5/02/12 , 9:55:20
PROGRAM MADG125
Holyoke Gas & Electric Department

Trial Balance

Page 2

Account	Description	Debit	Credit
0030-30-566-566-00-2	MISC TRANSMISSION PAYROLL	18,992.35	.00
ELECTRIC		18,992.35	.00
All Fund Totals		18,992.35	.00

HUDSON PTF SUPPORT PAYMENTS TO OTHERS FOR 2011

	HQ II AC <u>BEC</u>	HQ II AC <u>NEP</u>	HQ II Chester SVC <u>NEH</u>	Seabrook Tewksbury <u>NEP</u>	Seabrook Scobie & Newington <u>NU</u>	Millstone 3 <u>NU</u>	Wyman 4 <u>CMP</u>	Total	Seabrook Revenue Requirements	Support and Revenue Requirements Total
Hudson	\$ 575.00	\$ 9,747.00	\$ 4,114.00	\$ 7,087.00	\$ 6,697.00	\$ 3,736.00	\$ 325.00	<u>\$ 32,281.00</u>	\$76,880	<u>\$ 109,161.00</u>

Note: Amounts above Includes share of MMWEC projects and MJO shares for Seabrook

Reconciliation of amounts from MMWEC to total above:

Hudson - share of MMWEC	\$575	\$9,747	\$4,114	\$6,760	\$6,389	\$3,736	\$325	\$31,646	\$73,328	\$104,974
Hudson - MJO share Seabrook				\$327	\$308			\$635	\$3,552	\$4,187
Total PTF Support per above:	575	9,747	4,114	7,087	6,697	3,736	325	32,281	76,880	109,161

Hudson Light & Power Department**Annual Revenue Requirements
for costs in 2011**PTF Revenue Requirements
Worksheet 8 of 8

Sheet: Input Panel

NEPOOL Tariff Billing
NEPOOL Annual Transmission Revenue Requirements
per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3

Shading denotes an input

Submitted on:

15-May-11

Revised on:

N/A

Revenue Requirements for (year):

2011

Customer:

Hudson Light & Power Department

Customer's NABs Number:

Name of Participant responsible for customer's billing:

Hudson Light & Power Department

DUNs number of Participant responsible for customer's billing:

10-775-5126

	<u>Pre-97 Revenue Requirements</u>	<u>Post-97 Revenue Requirements</u>
Total of Attachment F - Sections A through I	<u>3,552</u> (a)	<u></u> (f)
Total of Attachment F - Section J - Support Revenue	<u>0</u> (b)	<u></u> (g)
Total of Attachment F - Section K - Support Expense	<u>0</u> (c)	<u></u> (h)
Total of Attachment F - Section (L through O)	<u>0</u> (d)	<u></u> (i)
Sub Total - Sum (A through I) - J + K + (L through O)	<u>3,552</u> (e)=(a)-(b)+(c)+(d)	<u></u> (j)
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:		<u>3,552</u> (k) = (e) + (j)
Total of Attachment F - Section J - Pre-97 Support Revenue (from above)		<u>0</u> (b)
Total of Attachment F - Section J - Post-96 Support Revenue (from above-)		<u>0</u> (g)
Total of Attachment F - Section K - Post-96 Support Expense (from above)		<u>0</u> (h)
Voting Share Total for Participant's R Value: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)		<u><u>3,552</u></u> (l)=(k)+(b)+(g)-(h)

Hudson Light & Power Department
Annual Revenue Requirements
for costs in 2011

PTF Revenue Requirements
Worksheet 1 of 8

Sheet: Worksheet 1

Shading denotes an input

		Attachment F		
		Reference		Reference
Line No.	I. INVESTMENT BASE	Section:		
1	Transmission Plant	(A)(1)(a)	24,230	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	0	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		24,230	
5	Accumulated Depreciation	(A)(1)(d)	853	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	0	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	0	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	0	Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		23,377	
10	Prepayments	(A)(1)(h)	15	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	293	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	127	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		23,812	
II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	1,905	Worksheet 2
15	Depreciation Expense	(B)	478	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	0	Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)	0	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	141	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	11	Worksheet 4, line 17 column 5
20	Operation & Maintenance Expense	(G)	976	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	41	Worksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	0	Worksheet 7
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	0	
28	Transmission Rents Received from Electric Property	(O)	0	Page 37 line 18b * TWSAF * PTFPAF
29	Total Revenue Requirements (Line 14 thru 28)		3,552	To Revenue Requirements Summary Sheet

Hudson Light & Power Department
Annual Revenue Requirements
for costs in 2011

Shading denotes an input

	CAPITALIZATION 12/31/00	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG TERM DEBT	\$ Not Applicable	#VALUE!		#VALUE!	
COMMON EQUITY		#VALUE!		#VALUE!	#VALUE!
TOTAL INVESTMENT RETURN	\$ n/a	#VALUE!		#VALUE!	#VALUE!

Cost of Capital Rate=

(a) Weighted Cost of Capital	=	0.0800	PROXY PER INTERPRETIVE GUIDANCE DOCUMENT FOR IMPLEMENTATION RULE SECTION II.A.2 FOR AN MTO
(b) Federal Income Tax	=	$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / \text{Federal Income Tax Rate}}{1 - \text{Federal Income Tax Rate}} \right) \times$	
	=	$\left(\frac{0.0000 + \left(\frac{0 + 0}{23,812} \right) / 0}{1 - 0} \right) \times$	
	=	0.0000000	
(c) State Income Tax	=	$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / \text{Federal Income Tax}}{1 - \text{State Income Tax Rate}} \right) \times \text{State Income Tax Rate}$	
	=	$\left(\frac{0.0000 + \left(\frac{0 + 0}{23,812} \right) / 0.0000000}{1 - 0} \right) \times 0$	
	=	0.0000000	
(a)+(b)+(c) Cost of Capital Rate	=	0.0800000	

	(PTF)	
INVESTMENT BASE	\$ 23,812	From Worksheet 1
x Cost of Capital Rate	0.0800000	
= Investment Return and Income Taxes	1,905	To Worksheet 1

Hudson Light & Power Department

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
<u>Transmission Plant</u>						
1	52,729	Directly Assigned	52,729		24,230	Line 1, Worksheet 5
2	0	0.5438% (a)	0	45.9509%	0	Page 8B, line 29g
3			52,729		24,230	
4	0		0	45.9509%	0	None known
<u>Transmission Accumulated Depreciation</u>						
5	1,855		1,855	45.9509%	853	Page 8A, line 31g less Page 16, line 31g
6	0	0.5438% (a)	0	45.9509%	0	Page 8B, line 29g less
7			1,855		853	Page 17, line 29g
<u>Transmission Accumulated Deferred Taxes</u>						
8	0	1.5252% (c)	0	45.9509%	0	None known
9	0	1.5252% (c)	0	45.9509%	0	None known
10			0		0	
11	0	1.5252% (c)	0	45.9509%	0	None known
<u>Other Regulatory Assets</u>						
12	0	0.5438% (a)	0	45.9509%	0	None known
13	0	1.5252% (c)	0	45.9509%	0	None known
14	0	1.5252% (c)	0	45.9509%	0	
15	0		0		0	
16	2,141	1.5252% (a)	33	45.9509%	15	Page 10, line 26c
17	41,733	1.5252% (a)	637	45.9509%	293	Page 14, line 16b
Per Guidance Document I. R. Section II.A.1 as well as Application of I. R. to MTO's						
<u>Cash Working Capital</u>						
19					976	Worksheet 1, Line 20
20					41	Worksheet 1, Line 21
21					0	Worksheet 1, Line 24
22					1,017	
23					0.125	x 45 / 360
24					127	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

Shading denotes an input

** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments

Hudson Light & Power Department**Annual Revenue Requirements
for costs in 2011**

Sheet: Worksheet 5

PTF Revenue Requirements
Worksheet 5 of 8

Shading denotes an input

Line
No.Mass DTE AR
Reference**PTF Transmission Plant Allocation Factor****0**

1 PTF Transmission Investment

24,230

5-Break Project Unitization Costs Sheet -
Rec'd from H. Person (Calc'd Hudson
Light & Power Department Share

2 Total Transmission Investment

52,729

5-Break Project Unitization Costs Sheet -
Rec'd from H. Person (Calc'd Hudson
Light & Power Department Share

3 Percent Allocation (Line 1/Line 2)

45.9509%

Transmission Wages and Salaries Allocation Factor

4 Direct Transmission Wages and Salaries

283

From 570 Labor Report per C. Blaine @
B-1 Seabrook

5 Affiliated Company Transmission Wages and Salaries

0

6 Total Transmission Wages and Salaries (Line 4 + Line 5)

283

7 Total Wages and Salaries

52,010

From Labor Report per C. Blaine @
C-1 Seabrook

8 Administrative and General Wages and Salaries

0

9 Affiliated Company Wages and Salaries less A&G

0

10 Total Wages and Salaries net of A&G (Line 7 - 8 + 9)

52,010

11 Percent Allocation (Line 6/Line 10)

0.5438%

Plant Allocation Factor

12 Total Transmission Investment

52,729

Per Above

13 *plus Transmission-Related General Plant (Line 2 of Wkst. 3)*

0

14 *= Revised Numerator (Line 12 + Line 13)*

52,729

15 Total Plant in Service

3,457,326

Per Hudson Light & Power Department
Accounting Records, less Accum
Depreciation

16 Percent Allocation (Line 14 / Line 15)

1.5252%

Hudson Light & Power Department

Annual Revenue Requirements for costs in 2011

Sheet: Worksheet 6

Affiliated Company Wages and Salaries

Shading denotes an input

Line		0
"Affiliated" Transmission Wages and Salaries #560 - 573		
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11 = 1 thru 10	Total Transmission	0
12 = Total "Affiliated" Wages and Salaries		
12 = 0		
Less "Affiliated" Administrative and General Salaries #920 - 935		
13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
21 = 13 thru 20		0
22 = 12 less 21 Total "Affiliated" less A&G		
22 = 0		

Hudson Light & Power Department

Annual Revenue Requirements for costs in 2011

PTF Revenue Requirements
Worksheet 7 of 8

Sheet: Worksheet 7

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	FERC Form 1	TOTAL	
			Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	332.(g); [332.1(g) for HWP]		0
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			0
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			0
	Comerford 115 kV Substation			
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	332.1(g); [332(g) for CL&P]		0
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 394 line	332(g)		0
	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			0
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		0
	345 kV Millstone-Manchester 310 line	330.1(n)		0
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
Total =			0	0

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

MMWEC Municipal Support of the New England PTF for 2011

MMWEC Municipal Support of the New England PTF for 2011											
	HQ II	HQ II	HQ II	Seabrook	Seabrook			MMWEC's			
	AC	AC	Chester	Tewksbury	Scobie &	Millstone 3	Wyman 4	Municipal	Seabrook	Support and	
			SVC		Newington			Support	Revenue	Revenue	
	Nstar (BECo)	NEP	NEH	NEP	NU	NU	CMP	Total	Requirements	Requirements	
										Total	
Hingham	\$ 469	7,941	3,352	2,006	1,896	3,563	-	\$ 19,227	21,758	\$ 40,985	
Hull	\$ 140	2,365	998	698	660	1,346	121	\$ 6,328	7,573	\$ 13,901	
								\$ -		\$ -	
Pascoag,RI	\$ 89	1,514	639	452	427	-	-	\$ 3,121	4,906	\$ 8,027	
								\$ -		\$ -	
Concord	\$ 468	7,921	3,344	-	-	-	-	\$ 11,733	-	\$ 11,733	
Ashburnham	\$ 69	1,176	496	276	261	1,086	-	\$ 3,364	2,990	\$ 6,354	
Boylston	\$ 78	1,326	560	359	339	934	50	\$ 3,646	3,896	\$ 7,542	
Danvers	\$ 933	15,810	6,674	4,709	4,450	9,294	-	\$ 41,870	51,072	\$ 92,942	
Georgetown	\$ 90	1,527	645	405	383	736	-	\$ 3,786	4,392	\$ 8,178	
Groton,MA	\$ 103	1,748	738	545	515	899	-	\$ 4,548	5,912	\$ 10,460	
Holden	\$ 287	4,867	2,054	1,681	1,588	2,569	-	\$ 13,046	18,228	\$ 31,274	
Ipswich	\$ -	-	-	451	426	2,151	-	\$ 3,028	4,890	\$ 7,918	
Littleton,MA	\$ 287	4,854	2,049	463	437	1,896	159	\$ 10,145	5,018	\$ 15,163	
Mansfield	\$ 653	11,053	4,666	3,345	3,161	5,594	-	\$ 28,472	36,277	\$ 64,749	
Marblehead	\$ 331	5,608	2,367	572	540	5,463	267	\$ 15,148	6,200	\$ 21,348	
Middleton	\$ 182	3,087	1,303	1,389	1,312	1,556	97	\$ 8,926	15,062	\$ 23,988	
N. Attleboro	\$ 423	7,174	3,028	1,600	1,512	6,171	159	\$ 20,067	17,354	\$ 37,421	
Paxton	\$ 68	1,157	488	342	323	1,154	-	\$ 3,532	3,709	\$ 7,241	
Peabody	\$ 1,106	18,728	7,905	4,784	4,521	10,505	-	\$ 47,549	51,886	\$ 99,435	
Rowley	\$ 61	1,040	439	-	-	-	-	\$ 1,540	-	\$ 1,540	
Shrewsbury	\$ 629	10,657	4,498	2,437	2,303	8,220	399	\$ 29,143	26,428	\$ 55,571	
Sterling	\$ -	-	-	865	817	1,040	-	\$ 2,722	9,382	\$ 12,104	
Templeton	\$ 213	3,607	1,522	816	771	2,476	-	\$ 9,405	8,847	\$ 18,252	
Wakefield	\$ 486	8,227	3,473	1,638	1,548	7,272	421	\$ 23,065	17,769	\$ 40,834	
W.Boylston	\$ 199	3,366	1,421	768	726	2,801	-	\$ 9,281	8,328	\$ 17,609	
								\$ -		\$ -	
Chicopee	\$ 1,228	20,794	8,778	-	-	-	-	\$ 30,800	-	\$ 30,800	
S.Hadley	\$ 451	7,642	3,226	1,444	1,365	20,364	-	\$ 34,492	15,665	\$ 50,157	
Westfield	\$ 986	16,700	7,049	1,543	1,458	39,383	694	\$ 67,813	16,735	\$ 84,548	
Total MMWEC Support:	\$ 10,029	\$ 169,889	\$ 71,712	\$ 33,588	\$ 31,739	\$ 136,473	\$ 2,367	\$ 455,797	\$ 364,277	\$ 820,074	
Reconciliation to MMWEC Amounts per Seabrook Reports:											
Hudson	\$575	\$9,747	\$4,114	\$6,760	\$6,389	\$3,736	\$325	\$31,646	\$73,328	\$104,974	These municipalities submit separately to the RWG as they include non-MMWEC contracts/shares in their filings
Holyoke	\$1,032	\$17,487	\$7,381	\$1,311	\$1,239	\$11,299	\$658	\$40,407	\$14,216	\$54,623	
Reading	\$1,813	\$30,710	\$12,963	\$2,689	\$2,541	\$14,298	\$0	\$65,014	\$29,163	\$94,177	
Braintree	\$1,203	\$20,378	\$8,602	\$2,596	\$2,453	\$0	\$0	\$35,232	\$28,157	\$63,389	
Middleborough	\$415	\$7,038	\$2,971	\$2,131	\$2,014	\$3,992	\$159	\$18,720	\$23,115	\$41,835	
Total MMWEC Share per Seabrook Reports:				49,075	46,375				532,256		

Massachusetts Municipal Wholesale Electric CompanyAnnual Revenue Requirements
for costs in 2011PTF Revenue Requirements
Worksheet 8 of 8

Sheet: Input Panel

NEPOOL Tariff Billing
NEPOOL Annual Transmission Revenue Requirements
per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3

Shading denotes an input

Submitted on:	15-May-11
Revised on:	N/A
Revenue Requirements for (year):	2011

Customer:	MMWEC

Customer's NABs Number:	

Name of Participant responsible for customer's billing:	MMWEC

DUNs number of Participant responsible for customer's billing:	071724900

		<u>Pre-97 Revenue Requirements</u>	<u>Post-97 Revenue Requirements</u>
Total of Attachment F - Sections A through I	=	<u>532,256</u> (a)	<u></u> (f)
Total of Attachment F - Section J - Support Revenue		<u>0</u> (b)	<u></u> (g)
Total of Attachment F - Section K - Support Expense		<u>0</u> (c)	<u></u> (h)
Total of Attachment F - Section (L through O)		<u>0</u> (d)	<u></u> (i)
Sub Total - Sum (A through I) - J + K + (L through O)		<u>532,256</u> (e)=(a)-(b)+(c)+(d)	<u></u> (j)

Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:	<u>532,256</u> (k) = (e) + (j)

Total of Attachment F - Section J - Pre-97 Support Revenue (from above)	<u>0</u> (b)

Total of Attachment F - Section J - Post-96 Support Revenue (from above-)	<u>0</u> (g)

Total of Attachment F - Section K - Post-96 Support Expense (from above)	<u>0</u> (h)

Voting Share Total for Participant's R Value:	<u><u>532,256</u></u> (l)=(k)+(b)+(g)-(h)
(for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)	

Shading denotes an input

		Attachment F Reference		Reference
Line No.	I. INVESTMENT BASE	Section:		
1	Transmission Plant	(A)(1)(a)	3,630,656	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	0	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		3,630,656	
5	Accumulated Depreciation	(A)(1)(d)	127,755	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	0	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	0	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	0	Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		3,502,901	
10	Prepayments	(A)(1)(h)	2,249	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	43,826	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	19,050	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		3,568,026	
II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	285,442	Worksheet 2
15	Depreciation Expense	(B)	71,647	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	0	Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)	0	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	21,095	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	1,676	Worksheet 4, line 17 column 5
20	Operation & Maintenance Expense	(G)	146,302	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	6,094	Worksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	0	Worksheet 7
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	0	
28	Transmission Rents Received from Electric Property	(O)	0	Page 37 line 18b * TWSAF * PTFPAF
29	Total Revenue Requirements (Line 14 thru 28)		532,256	To Revenue Requirements Summary Sheet

Massachusetts Municipal Wholesale Electric Company
Annual Revenue Requirements
for costs in 2011

Shading denotes an input

	CAPITALIZATION 12/31/00	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG TERM DEBT	\$ Not Applicable	#VALUE!		#VALUE!	
COMMON EQUITY		#VALUE!		#VALUE!	
		#VALUE!		#VALUE!	#VALUE!
TOTAL INVESTMENT RETURN	\$ n/a	#VALUE!		#VALUE!	#VALUE!

Cost of Capital Rate=

(a) Weighted Cost of Capital	=	0.0800	PROXY PER INTERPRETIVE GUIDANCE DOCUMENT FOR IMPLEMENTATION RULE SECTION II.A.2 FOR AN MTO
(b) Federal Income Tax	=	$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / \text{Federal Income Tax Rate}}{1 - \text{Federal Income Tax Rate}} \right)$	
	=	$\left(\frac{0.0000 + \left(\frac{0 + 0}{3,568,026} \right) / 0}{1 - 0} \right)$	
	=	0.0000000	
(c) State Income Tax	=	$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / \text{Federal Income Tax}}{1 - \text{State Income Tax Rate}} \right) * \text{State Income Tax Rate}$	
	=	$\left(\frac{0.0000 + \left(\frac{0 + 0}{3,568,026} \right) / 0.0000000}{1 - 0} \right) * 0$	
	=	0.0000000	
(a)+(b)+(c) Cost of Capital Rate	=	0.0800000	

	(PTF)	
INVESTMENT BASE	\$ 3,568,026	From Worksheet 1
x Cost of Capital Rate	0.0800000	
= Investment Return and Income Taxes	285,442	To Worksheet 1

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
<u>Transmission Plant</u>						
1	7,901,166	Directly Assigned	7,901,166		3,630,656	Line 1, Worksheet 5
2	0	0.5438% (a)	0	45.9509%	0	Page 8B, line 29g
3			7,901,166		3,630,656	
4	0		0	45.9509%	0	None known
<u>Transmission Accumulated Depreciation</u>						
5	278,025		278,025	45.9509%	127,755	Page 8A, line 31g less Page 16, line 31g
6	0	0.5438% (a)	0	45.9509%	0	Page 8B, line 29g less
7			278,025		127,755	Page 17, line 29g
<u>Transmission Accumulated Deferred Taxes</u>						
8	0	1.5252% (c)	0	45.9509%	0	None known
9	0	1.5252% (c)	0	45.9509%	0	None known
10			0		0	
11	0	1.5252% (c)	0	45.9509%	0	None known
<u>Other Regulatory Assets</u>						
12	0	0.5438% (a)	0	45.9509%	0	None known
13	0	1.5252% (c)	0	45.9509%	0	None known
14	0	1.5252% (c)	0	45.9509%	0	
15	0		0		0	
16	320,879	1.5252% (a)	4,894	45.9509%	2,249	Page 10, line 26c
17	6,253,358	1.5252% (a)	95,376	45.9509%	43,826	Page 14, line 16b
Per Guidance Document I. R. Section II.A.1 as well as Application of I. R. to MTO's						
18	<u>Cash Working Capital</u>					
19	Operation & Maintenance Expense				146,302	Worksheet 1, Line 20
20	Administrative & General Expense				6,094	Worksheet 1, Line 21
21	Transmission Support Expense				0	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)				152,396	
23					0.125	x 45 / 360
24	Total (line 22 * line 23)				19,050	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments

Massachusetts Municipal Wholesale Electric Company**Annual Revenue Requirements
for costs in 2011**PTF Revenue Requirements
Worksheet 5 of 8

Sheet: Worksheet 5

Shading denotes an input

Line No.			Mass DTE AR Reference
	<u>PTF Transmission Plant Allocation Factor</u>	0	
1	PTF Transmission Investment	3,630,656	5-Break Project Unitization Costs Sheet - Rec'd from H. Person (Calc'd MMWEC Share
2	Total Transmission Investment	7,901,166	5-Break Project Unitization Costs Sheet - Rec'd from H. Person (Calc'd MMWEC Share
3	Percent Allocation (Line 1/Line 2)	45.9509%	
	<u>Transmission Wages and Salaries Allocation Factor</u>		
4	Direct Transmission Wages and Salaries	42,377	From 570 Labor Report per C. Blaine @
5	Affiliated Company Transmission Wages and Salaries	0	B-1 Seabrook
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	42,377	
7	Total Wages and Salaries	7,793,419	From Labor Report per C. Blaine @
8	Administrative and General Wages and Salaries		C-1 Seabrook
9	Affiliated Company Wages and Salaries less A&G	0	
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	7,793,419	
11	Percent Allocation (Line 6/Line 10)	0.5438%	
	<u>Plant Allocation Factor</u>		
12	Total Transmission Investment	7,901,166	Per Above
13	plus Transmission-Related General Plant (Line 2 of Wkst. 3)	0	
14	= Revised Numerator (Line 12 + Line 13)	7,901,166	
15	Total Plant in Service	518,058,259	Per MMWEC Accounting Records, less Accum Depreciation
16	Percent Allocation (Line 14 / Line 15)	1.5252%	

Massachusetts Municipal Wholesale Electric Company**Annual Revenue Requirements
for costs in 2011**

Sheet: Worksheet 6

Affiliated Company Wages and Salaries

Shading denotes an input

Line		0
"Affiliated" Transmission Wages and Salaries #560 - 573		
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11 = 1 thru 10	Total Transmission	0
12 = Total "Affiliated" Wages and Salaries		
Less "Affiliated" Administrative and General Salaries #920 - 935		
13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
21 = 13 thru 20		0
22 = 12 less 21	Total "Affiliated" less A&G	0

Massachusetts Municipal Wholesale Electric Company

Annual Revenue Requirements for costs in 2011

PTF Revenue Requirements
Worksheet 7 of 8

Sheet: Worksheet 7

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	FERC Form 1	TOTAL	
			Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	332.(g); [332.1(g) for HWP]		0
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			0
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			0
	Comerford 115 kV Substation			
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	332.1(g); [332(g) for CL&P]		0
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 394 line	332(g)		0
	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			0
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		0
	345 kV Millstone-Manchester 310 line	330.1(n)		0
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
Total =			0	0

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

**MAINE ELECTRIC POWER COMPANY
RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

ISO-NE Tariff Billing
PTO Annual Transmission Revenue Requirements
per OATT Attachment F

Shading denotes an input

Submitted on: May 14, 2012

Revenue Requirements for (year): Calendar Year 2011

Customer: Maine Electric Power Company

Customer's NABs Number:

Name of Participant responsible for customer's billing: Central Maine Power

DUNs number of Participant responsible for customer's billing: 006948954

		<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>
Total of Attachment F - Sections A through I	=	1,729,976 (a)	395,440 (f)
Total of Attachment F - Section J - Support Revenue		<u>0 (b)</u>	<u>0 (g)</u>
Total of Attachment F - Section K - Support Expense		<u>0 (c)</u>	<u>0 (h)</u>
Total of Attachment F - Section (L through P)		<u>(2,826,800) (d)</u>	<u>(646,154) (i)</u>
Sub Total - Sum (A through I) - J + K + (L through P)		<u>(1,096,825) (e)=(a)-(b)+(c)+(d)</u>	<u>(250,713) (j)</u>
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:			<u>(1,347,538) (k) = (e) + (j)</u>

**MAINE ELECTRIC POWER COMPANY
RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

Inputs

			Attachment F	TOTAL	POST 96	PRE-97		
			Reference	MEPCO			Reference	
Line No.	I. INVESTMENT BASE		Section:					
1	Transmission Plant	(A)(1)(a)		25,872,777	4,813,708	21,059,069	Worksheet 3, line 1 column 5	
2	General Plant	(A)(1)(b)		1,242,710	231,210	1,011,500	Worksheet 3, line 2 column 5	
3	Plant Held For Future Use	(A)(1)(c)		-	-	-	Worksheet 3, line 4 column 5	
4	Total Plant (Lines 1+2+3)			27,115,487	5,044,918	22,070,569		
5	Accumulated Depreciation	(A)(1)(d)		(24,681,943)	(4,592,150)	(20,089,793)	Worksheet 3, line 7 column 5	
6	Accumulated Deferred Income Taxes	(A)(1)(e)		1,084,954	201,859	883,095	Worksheet 3, line 10 column 5	
7	Loss On Reacquired Debt	(A)(1)(f)		-	-	-	Worksheet 3, line 11 column 5	
8	Other Regulatory Assets/(Liabilities)	(A)(1)(g)		(601,619)	(111,933)	(489,686)	Worksheet 3, line 14 column 5	
9	Net Investment (Line 4+5+6+7+8)			2,916,879	542,694	2,374,185		
10	Prepayments	(A)(1)(h)		220,082	40,947	179,135	Worksheet 3, line 15 column 5	
11	Materials & Supplies	(A)(1)(i)		-	-	-	Worksheet 3, line 16 column 5	
12	Cash Working Capital	(A)(1)(j)		115,048	21,405	93,643	Worksheet 3, line 23 column 5	
13	Total Investment Base (Line 9+10+11+12)			3,252,009	605,046	2,646,962		
II. REVENUE REQUIREMENTS								
14	Investment Return and Income Taxes	(A)		639,464	118,974	520,490	Worksheet 2	
15	Depreciation Expense	(B)		234,592	43,647	190,945	Worksheet 4, line 3 column 5	
16	Amortization of Loss on Reacquired Debt	(C)		-	-	-	Worksheet 4, line 4 column 5	
17	Investment Tax Credit	(D)		-	-	-	Worksheet 4, line 5 column 5	
18	Property Tax Expense	(E)		330,980	61,580	269,400	Worksheet 4, line 8 column 5	
19	Payroll Tax Expense	(F)		-	-	-	Worksheet 4, line 17 column 5	
20	Operation & Maintenance Expense	(G)		747,190	139,017	608,173	Worksheet 4, line 13 column 5	
21	Administrative & General Expense	(H)		173,190	32,223	140,967	Worksheet 4, line 16 column 5	
22	Transmission Related Integrated Facilities Charge	(I)		-	-	-		
23	Transmission Support Revenue	(J)		-	-	-		
24	Transmission Support Expense	(K)		-	-	-		
25	Transmission Related Expense from Generators	(L)		-	-	-		
26	Transmission Related Taxes and Fees Charge	(M)		-	-	-		
27	Revenue for Trans. Service Under ISO Tariff	(N)		(2,263,313)	(421,096)	(1,842,217)	FFI p450 notes for p328 7.m.	
28	Transmission Rents Received from Electric Property	(O)		(254,766)	(47,400)	(207,366)	FF I p.300.19.b	
28	MG TSA Revenue	(P)		(954,875)	(177,657)	(777,218)	FF I p.330.1-7.n	
29	Total Revenue Requirements (Line 14 thru 28)			(1,347,538)	(250,713)	(1,096,825)		

**MAINE ELECTRIC POWER COMPANY
RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

Shading denotes an input

	CAPITALIZATION 12/31/2011		CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ -		0.00%	0.00%	0.00%	
PREFERRED STOCK	-		0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	8,351,096	FF1.112.16.c	100.00%	11.64%	11.64%	11.64%
TOTAL INVESTMENT RETURN	\$ 8,351,096		100.00%		11.64%	11.64%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.1164

(b) Federal Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right)}{1} \right) \times \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}}$$

=
$$\left(\frac{0.1164 + \left(\frac{- + -}{3,252,009} \right)}{1} \right) \times \frac{35\%}{0.35}$$

= 0.0626769

(c) State Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right)}{1} \right) + \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}} \times \text{State Income Tax Rate}$$

=
$$\left(\frac{0.1164 + \left(\frac{- + -}{3,252,009} \right)}{1} \right) + \frac{0.0626769}{0.0893} \times 8.93\%$$

= 0.0175596

(a)+(b)+(c) Cost of Capital Rate = 0.1966365

	(PTF)	
INVESTMENT BASE	\$ 3,252,009	From Worksheet 1
x Cost of Capital Rate	0.1966365	
= Investment Return and Income Taxes	639,464	To Worksheet 1

**MAINE ELECTRIC POWER COMPANY
RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form I Reference for col (1)
<u>Transmission Plant</u>						
1	25,872,777		25,872,777		25,872,777	207.58.g
2	1,242,710	100.0000% (a)	1,242,710	100.0000%	1,242,710	207.99.g
3			<u>27,115,487</u>		<u>27,115,487</u>	
4	-		-	100.0000%	-	
<u>Transmission Accumulated Depreciation</u>						
5	(23,445,122)		(23,445,122)	100.0000%	(23,445,122)	219.25.b
6	(1,236,821)	100.0000% (a)	(1,236,821)	100.0000%	(1,236,821)	219.28.b
7			<u>(24,681,943)</u>		<u>(24,681,943)</u>	
<u>Transmission Accumulated Deferred Taxes</u>						
8	(204,719)	99.8775% (c)	(204,468)	100.0000%	(204,468)	275.9.k + 277.19.k
9	1,291,003	99.8775% (c)	1,289,422	100.0000%	1,289,422	234.8.c
10			<u>1,084,954</u>		<u>1,084,954</u>	
11	-	99.8775% (c)	-	100.0000%	-	
<u>Other Regulatory Assets/(Liabilities)</u>						
12	-	100.0000% (a)	-	100.0000%	-	
13	(602,357)	99.8775% (c)	(601,619)	100.0000%	(601,619)	113.60.c
14	-	99.8775% (c)	-	100.0000%	-	
15	<u>(602,357)</u>		<u>(601,619)</u>		<u>(601,619)</u>	
16	220,082	100.0000% (a)	220,082	100.0000%	220,082	111.57.c
17	-	99.8775%	-	100.0000%	-	
<u>Cash Working Capital</u>						
18						
19					747,190	Worksheet 1, Line 20
20					173,190	Worksheet 1, Line 21
21					-	Worksheet 1, Line 24
22					920,380	
23					0.125	x 45 / 360
24					<u>115,048</u>	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

**MAINE ELECTRIC POWER COMPANY
RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

		(2)	(4)				
Shading denotes an input							
Line No.		(1) Total	Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form I Reference for col (1)
	<u>Depreciation Expense</u>						
1	Transmission Depreciation	225,547		225,547	100.0000%	225,547	336.7.f
2	General Depreciation	9,045	100.0000% (a)	9,045	100.0000%	9,045	336.9.f
3	Total (line 1+2)			234,592		234,592	
4	<u>Amortization of Loss on Reacquired Debt</u>	-	99.8775% (c)	-	100.0000%	-	
5	<u>Amortization of Investment Tax Credits</u>	-	99.8775% (c)	-	100.0000%	-	
	<u>Property Taxes *</u>						
6	Transmission Property Taxes	331,386	0.998775	330,980	100.0000%	330,980	263.5i-9i
7	General Property Taxes	-	100.0000% (a)	-	100.0000%	-	
8	Total (line 6+7)			330,980		330,980	
	<u>Transmission Operation and Maintenance</u>						
9	Operation and Maintenance	986,714		986,714	100.0000%	986,714	321.112.b
10	Transmission of Electricity by Others - #565	-		-	100.0000%	-	
11	Load Dispatching - #561	239,524		239,524	100.0000%	239,524	321.85b+86b
12	**Station Expenses & Rents - #562 / #567	-		-	100.0000%	-	
13	O&M less lines 10, 11 & 12	747,190		747,190	100.0000%	747,190	
	<u>Transmission Administrative and General</u>						
14	Administrative and General	173,204					323.194.b
15	less Property Insurance (#924)	11,118					323.185.b
16	less Regulatory Commission Expenses (#928)	46,807					323.189.b
17	less General Advertising Expense (#930.1)	-					
18	Subtotal [line 14 minus (15 thru 17)]	115,279	100.0000% (a)	115,279	100.0000%	115,279	
19	PLUS Property Insurance alloc. using Plant Allocation	11,118	99.8775% (c)	11,104	100.0000%	11,104	323.185.b
20	PLUS Regulatory Comm. Exp. (FERC Assessments)	46,807	100.0000%	46,807	100.0000%	46,807	323.189.b
21	PLUS Trans. Related General Advertising Expense	-	99.8775% (c)	-	100.0000%	-	
22	Total A&G [line 18 plus (19 thru 21)]	173,204		173,190		173,190	
23	<u>Payroll Tax Expense</u>	-	100.0000% (a)	-	100.0000%	-	

(a) Worksheet 5 of 8, line 11
(b) Worksheet 5 of 8, line 3
(c) Worksheet 5 of 8, line 16
(d) Directly Assigned per Att F

**MAINE ELECTRIC POWER COMPANY
RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

Shading denotes an input

Line No.			Reference
	<u>PTF Transmission Plant Allocation Factor</u>	MEPCO	
1	PTF Transmission Investment	25,872,777	207.58.g
2	Total Transmission Investment	25,872,777	207.58.g
3	Percent Allocation (Line 1/Line 2)	100.0000%	
	<u>Transmission Wages and Salaries Allocation Factor</u>		
4	Direct Transmission Wages and Salaries	100%	
5	Affiliated Company Transmission Wages and Salaries	0	
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	100%	
7	Total Wages and Salaries	100%	
8	Administrative and General Wages and Salaries	0	
9	Affiliated Company Wages and Salaries less A&G	0	
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	100%	
11	Percent Allocation (Line 6/Line 10)	100.0000%	
	<u>Plant Allocation Factor</u>		
12	Total Transmission Investment	25,872,777	Line 2
13	plus Transmission-Related General Plant (Line 2 of Wkst. 3)	1,242,710	Worksheet 3, Line 2
14	= Revised Numerator (Line 12 + Line 13)	27,115,487	
15	Total Plant in Service	27,148,757	207.104.g
16	Percent Allocation (Line 14 / Line 15)	99.8775%	

**MAINE ELECTRIC POWER COMPANY
RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

Affiliated Company Wages and Salaries

Shading denotes an input

Line		<u>MEPCO</u>
"Affiliated" Transmission Wages and Salaries #560 - 573		
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11 = 1 thru 10	Total Transmission	0
12 = Total "Affiliated" Wages and Salaries		0
Less "Affiliated" Administrative and General Salaries #920 - 935		
13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
21 = 13 thru 20		0
22 = 12 less 21	Total "Affiliated" less A&G	0

**MAINE ELECTRIC POWER COMPANY
RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	FERC Form 1	TOTAL	
			Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	332.(g); [332.1(g) for HWP]		0
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			0
	Comerford 115 kV Substation			
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	332.1(g); [332(g) for CL&P]		0
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 394 line	332(g)		0
	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			0
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310 line	330.1(n)		
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
Total =				0

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

**MAINE ELECTRIC POWER COMPANY
RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/11**

MEPCO Transmission Investment by Vintage
as of 12/31/2011

Functional Class	(Multiple Items)	
Sum of Accumulated Cost		
Vintage	Total	
1900	(82.50)	
1970	9,699,785.98	
1971	7,748,843.84	
1972	5,440.67	
1973	28,969.36	
1974	1,242.56	
1975	92,738.01	
1976	1,888.47	
1977	617.48	
1978	18.55	
1982	1,200.00	
1984	908,419.85	
1985	531,332.55	
1986	978,792.04	
1988	(2,000.00)	
1990	304,541.27	
1991	90,622.02	
1992	390,255.57	
1993	257,335.81	
1996	19,106.85	21,059,068.38 Pre1997
1997	298,692.55	
1998	111,013.67	
2000	2,397,044.28	
2001	149,511.05	
2002	87,394.70	
2003	630,493.69	
2004	-	
2005	(0.00)	
2006	-	
2007	262,838.89	
2008	312,465.30	
2009	136,311.57	
2010	319,125.09	
2011	108,817.19	4,813,707.98 Post1996
Grand Total	25,872,776.36	25,872,776.36

Middleborough Gas and Electric Department

Sheet: Input Panel

Input Panel

Regional Network Service
Annual Transmission Revenue Requirements
per Attachment F of the ISO New England Inc. Open Access Transmission Tariff

Shading denotes an input

Submitted on: 05/18/2012

Revenue Requirements for (year): 2011

Customer: Middleborough Gas and Electric Department

Customer's NABs Number: 79

Name of Participant responsible for customer's billing: John Granahan

DUNs number of Participant responsible for customer's billing: 15-997-6665

	Pre-97 Revenue Requirements	Post-96 Revenue Requirements
Total of Attachment F - Sections A through I =	3,180 (a)	208,870 (f)
Total of Attachment F - Section J - Support Revenue	0 (b)	0 (g)
Total of Attachment F - Section K - Support Expense	318,004 (c)	0 (h)
Total of Attachment F - Section L through O	0 (d)	0 (i)
Sub Total - Sum (A through I) - J + K + (L through O)	321,184 (e)=(a)-(b)+(c)+(d)	208,870 (j)=(f)-(g)+(h)+(i)
Forecasted Incremental Transmission Revenue Requirements		0 (m)
Annual True-up	278,934	208,870 (n)
Interest Charge on Annual True-up	9,295 (l)	6,960 (o)
Total = (e) + (j) + (k) + (l) + (m) + (n) + (o)	609,413 (p)	424,700 (q)
Annual Projected 2008 Revenue Requirement Total = Sum of Pre-97 Revenue Requirements, plus Post-96 Revenue Requirements, plus Annual True-up, and plus Interest on Annual True-up:		1,034,113 (r) = (p)+(q)

Middleborough Gas and Electric Department
Annual Revenue Requirements of pre-1997 & post-1996 PTF
for costs in 2011 and billed 06/11-05/12

RNS Rate

		Attachment F			
		Reference	Pre 1997	Post 1996	Reference
Line No.	I. INVESTMENT BASE	Section:			
1	Transmission Plant	I (A)(1)(a)	0	0	Worksheet 3, line 1 column 5
2	General Plant	I (A)(1)(b)	0	0	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	I (A)(1)(c)	0	0	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		0	0	
5	Accumulated Depreciation	I (A)(1)(d)	0	0	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	I (A)(1)(e)	0	0	Worksheet 3, line 10 column 5
7	Loss On Recquired Debt	I (A)(1)(f)	0	0	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	I (A)(1)(g)	0	0	Worksheet 3, line 15 column 5
9	Net Investment (Line 4-5-6+7+8)		0	0	
10	Prepayments	I (A)(1)(h)	0	0	Worksheet 3, line 16 column 5
11	Materials & Supplies	I (A)(1)(i)	0	0	Worksheet 3, line 17 column 5
12	Cash Working Capital	I (A)(1)(j)	0	0	Worksheet 3, line 24 column 5
13	Total Investment Base (Line 9+11+12+13)		0	0	
II. REVENUE REQUIREMENTS					
14	Investment Return and Income Taxes	I (A)	0	-	Worksheet 2
15	Depreciation Expense	I (B)	0	-	Worksheet 4, line 3 column 5
16	Amortization of Loss on Recquired Debt	I (C)	0	-	Worksheet 4, line 4 column 5
17	Investment Tax Credit	I (D)	0	-	Worksheet 4, line 5 column 5
18	Property Taxes	I (E)	0	-	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	I (F)	0	-	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	I (G)	0	-	Worksheet 4, line 13 column 5
21	Administrative & General Expense	I (H)	0	-	Worksheet 4, line 22 column 5
22	Transmission Related Integrated Facilities Charge	I (I)	0	0	
23	Transmission Support Revenue	I (J)	0	0	Worksheet 7
24	Transmission Support Expense	I (K)	42,250	0	Worksheet 7
25	Transmission Related Expense from Generators	I (L)	0	0	
26	Transmission Related Taxes and Fees Charge	I (M)	0	0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	I (N)	0	0	Txm related Acct 456
28	Transmission Rents Received from Electric Properties	I (O)	0	0	Txm related Acct 454-rent
29	Total Revenue Requirements (Line 14 thru 28)		42,250	0	
III. CURRENT CALENDAR YEAR ESTIMATED INCREMENTAL REVENUE REQUIREMENT					
30	Carrying Charge Factor Base Revenue Requirement Numerator			0	
31	Post-2003 Enhanced Return Addition to Revenue Requirement			-	
32	Total Post-96 PTF Revenue Requirement			0	
33	Post-96 PTF Transmission Plant in Service			1,370,897	
34	Post-96 Carrying Charge Factor (Post-96 CCF)			0.0%	
35	Forecasted Post-96 PTF Plant Additions			0	
36	Forecasted Post-96 Localized PTF Plant Additions			0	
37	Forecasted Post-96 Pool-Supported PTF Plant Additions			0	
38	Post-96 Estimated Incremental Revenue Requirement			0	

RNS Rate

Middleborough Gas and Electric Department
FERC Interest Calculation associated with Under / (Over)
True Up and Interest Calculation for 2011

1 2011 Actual Annual RR			321,184	208,870	Input Panel Subtotals
2 2011 Est. Transmission Revenue Requirements (as billed)	6/11-05/12	Appendix C	42,250	0	ATRR - Prior Year
3 True-up (Over)/Under (Line 1 - Line 2)			278,934	208,870	

	Overcollection/(Undercollection)
Pre'97	\$278,934
Post'96	\$208,870

Initial Billing Period	Pre 1997 Balance	Post 1996 Balance	FERC Monthly Interest Rate	Pre 1997 Interest	Post 1996 Interest
June 2011	\$278,934	\$208,870	0.27%	\$753	\$564
July 2011	279,687	209,434	0.27%	755	\$565
August 2011	279,687	209,434	0.28%	783	\$586
September 2011	279,687	209,434	0.27%	755	\$565
October 2011	281,981	211,151	0.28%	790	\$591
November 2011	281,981	211,151	0.27%	761	\$570
December 2011	281,981	211,151	0.28%	790	\$591
January 2012	284,321	212,904	0.28%	796	\$596
February 2012	284,321	212,904	0.26%	739	\$554
March 2012	284,321	212,904	0.28%	796	\$596
April 2012	286,652	214,650	0.27%	774	\$580
May 2012	286,652	214,650	0.28%	803	\$601
		Total Interest		\$9,295	\$6,960
		True-Up		\$278,934	\$208,870
		Total TU & Int		\$288,229	\$215,830

Sheet: Input Panel

NEPOOL Tariff Billing
NEPOOL Annual Transmission Revenue Requirements
per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3

PRE 97

Shading denotes an input

Submitted on: 18-May-12

Revenue Requirements for (year): Calendar Year 2011

Customer: Middleborough Gas and Electric Department

Customer's NABs Number: 79

Name of Participant responsible for customer's billing: John Granahan

DUNs number of Participant responsible for customer's billing: 15-597-6665

	<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>
Total of Attachment F - Sections A through I =	<u>3,180</u> (a)	<u> </u> (f)
Total of Attachment F - Section J - Support Revenue	<u>0</u> (b)	<u>0</u> (g)
Total of Attachment F - Section K - Support Expense	<u>318,004</u> (c)	<u>0</u> (h)
Total of Attachment F - Section (L through O)	<u>0</u> (d)	<u>0</u> (i)
Sub Total - Sum (A through I) - J + K + (L through O)	<u>321,184</u> (e)=(a)-(b)+(c)+(d)	<u>0</u> (j)
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:		<u>321,184</u> (k) = (e) + (j)
Total of Attachment F - Section J - Pre-97 Support Revenue (from above)		<u>0</u> (b)
Total of Attachment F - Section J - Post-96 Support Revenue (from above-)		<u>0</u> (g)
Total of Attachment F - Section K - Post-96 Support Expense (from above)		<u>0</u> (h)
Voting Share Total for Participant's R Value: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)		<u><u>321,184</u></u> (l)=(k)+(b)+(g)-(h)

Shading denotes an input

		Attachment F		
		Reference	Middleborough	Reference
Line No.	I. INVESTMENT BASE	Section:		
1	Transmission Plant	(A)(1)(a)	0	Worksheet 3a, L10
2	General Plant	(A)(1)(b)	0	Worksheet 3a, L11
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3a, L14
4	Total Plant (Lines 1+2+3)		0	
5	Accumulated Depreciation	(A)(1)(d)	0	Worksheet 3a, L19
6	Accumulated Deferred Income Taxes	(A)(1)(e)	0	Worksheet 3a, L24
7	Loss On Reacquired Debt	(A)(1)(f)	0	Worksheet 3a, L26
8	Other Regulatory Assets	(A)(1)(g)	0	Worksheet 3a, L32
9	Net Investment (Line 4-5-6+7+8)		0	
10	Prepayments	(A)(1)(h)	0	Worksheet 3a, L34
11	Materials & Supplies	(A)(1)(i)	0	Worksheet 3a, L36
12	Cash Working Capital	(A)(1)(j)	39,751	Worksheet 3a, 44
13	Total Investment Base (Line 9+10+11+12)		39,751	
II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	3,180	Worksheet 2a, E56
15	Depreciation Expense	(B)	0	Worksheet 4a, L12
16	Amortization of Loss on Reacquired Debt	(C)	0	Worksheet 4a, L14
17	Investment Tax Credit	(D)	0	Worksheet 4a, L16
18	Property Tax Expense	(E)	0	Worksheet 4a, L21
19	Payroll Tax Expense	(F)	0	Worksheet 4a, L42
20	Operation & Maintenance Expense	(G)	0	Worksheet 4a, L29
21	Administrative & General Expense	(H)	0	Worksheet 4a, L40
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	318,004	Worksheet 7, E51
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	0	
28	Transmission Rents Received from Electric Property	(O)	0	
29	Total Revenue Requirements (Line 14 thru 28)		321,184	
			3,180	

Middleborough Gas and Electric Department

**Annual Revenue Requirements - 2012
for costs in 2011**

Shading denotes an input

	CAPITALIZATION 12/31/2009	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 109,845,000	100.00%	8.00%	8.00%	
PREFERRED STOCK	0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	0	0.00%	0.00%	0.00%	0.00%
TOTAL INVESTMENT RETURN	\$ 109,845,000	100.00%		8.00%	0.00%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0800

(b) Federal Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / \text{Federal Income Tax Rate}}{1} \right) \times \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}}$$

=
$$\left(\frac{0.0000 + \left(\frac{0 + 0}{39,751} \right)}{1} \right) \times \frac{0}{0}$$

= 0.0000000

(c) State Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / \text{Federal Income Tax Rate}}{1} \right) + \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}} \times \text{State Income Tax Rate}$$

=
$$\left(\frac{0.0000 + \left(\frac{0 + 0}{39,751} \right)}{1} \right) + \frac{0.0000000}{0} \times 0$$

= 0.0000000

(a)+(b)+(c) **Cost of Capital Rate** = 0.0800000

	(PTF)	
INVESTMENT BASE	\$ 39,751	From Worksheet 1
x Cost of Capital Rate	0.0800000	
= Investment Return and Income Taxes	<u>3,180</u>	To Worksheet 1

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Mass DTE AR Reference for col (1)
<u>Transmission Plant</u>						
1	\$ 2,914,018		2,914,018		0	Worksheet 5, E12
2	\$ 5,887,657	0.4621% (a)	27,207	0.0000%	0	Page 8B line 29(g)
3			2,941,225		0	
4	0		0	0.0000%	0	None known
<u>Transmission Accumulated Depreciation</u>						
5	1,106,486		1,106,486	0.0000%	0	Page 8A, line 31(g) less Page 16, line 31(g)
6	3,896,419	0.4621% (a)	18,005	0.0000%	0	Page 8B, line 29(g) less Page 17, line 29(g)
7			1,124,491		0	
<u>Transmission Accumulated Deferred Taxes</u>						
8	0	7.4891% (c)	0	0.0000%	0	None known
9	0	7.4891% (c)	0	0.0000%	0	None known
10			0		0	
11	0	7.4891% (c)	0	0.0000%	0	None known
<u>Other Regulatory Assets</u>						
12	0	0.4621% (a)	0	0.0000%	0	None known
13	0	7.4891% (c)	0	0.0000%	0	None known
14	0	7.4891% (c)	0	0.0000%	0	
15	0		0		0	
16	0	0.4621% (a)	0	0.0000%	0	Page 10, Line 26 MA DTE
17	0	0.4621%	0	0.0000%	0	Page 10, Line 24 MA DTE
<u>Cash Working Capital</u>						
19					0	Worksheet 1, Line 20
20					0	Worksheet 1, Line 21
21					318,004	Worksheet 1, Line 24
22					318,004	
23					0.125	x 45 / 360
24					39,751	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

Middleborough Gas and Electric Department

PTF Revenue Requirements
Worksheet 4 of 7

Sheet: Worksheet 4

		(2)	(4)			
Shading denotes an input						
Line No.	(1) Total	Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Mass DTE AR Reference for col (1)
<u>Depreciation Expense</u>						
1	145,701		145,701	0.0000%	0	Page 16, line 31(d)
2	282,539	0.4621% (a)	1,306	0.0000%	0	Page 17, line 29(d)
3			147,007		0	
4	0	7.4891% (c)	0	0.0000%	0	None known
5	0	7.4891% (c)	0	0.0000%	0	None known
<u>Property Taxes *</u>						
6	502,533	0.074891	37,635	0.0000%	0	Page 21, line 33 (b)
7	502,533	0.4621% (a)	2,322	0.0000%	0	Page 21, line 33 (b)
8			39,957		0	
<u>Transmission Operation and Maintenance</u>						
9	3,373,917		3,373,917	0	0	Page 40, line 50(b)
10	3,280,734		3,280,734	0	0	Page 40, line 38(b)
11	0		0	0	0	Page 40, line 34(b)
12	0		0	0	0	Page 40, line 35(b) 40(b)
13	93,183		93,183	0.0000%	0	
<u>Transmission Administrative and General</u>						
14	3,753,341					Page 42, line 5(b)
15	1					Page 41, line 47(b)
16	0					Page 41, line 50(b)
17	45,994					assumed none
18	3,707,346	0.4621% (a)	17,132	0.0000%	0	
19	1	7.4891% (c)	0	0.0000%	0	
20	0	7.4891% (c)	0	0.0000%	0	
21	0	7.4891% (c)	0	0.0000%	0	
22	3,707,347		17,132		0	
23	0	0.4621% (a)	0	0.0000%	0	Per company workpapers

- (a) Worksheet 5 of 8, line 11
(b) Worksheet 5 of 8, line 3
(c) Worksheet 5 of 8, line 16

Shading denotes an input

<u>Line No.</u>	<u>Mass DTE AR Reference</u>

PTF Transmission Plant Allocation Factor**Middleborough**

1	PTF Transmission Investment	0	Per Company Workpapers
2	Total Transmission Investment	2,914,018	Page 8A, line 31(g)
3	Percent Allocation (Line 1/Line 2)	0.0000%	

Transmission Wages and Salaries Allocation Factor

4	Direct Transmission Wages and Salaries	13,775	See MGED General Ledger
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 of 7
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	13,775	
7	Total Wages and Salaries	3,289,546	Page 42, line 24 (c)
8	Administrative and General Wages and Salaries	308,472	Page 41, line 43(b)
9	Affiliated Company Wages and Salaries less A&G	0	Worksheet 6
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	2,981,074	
11	Percent Allocation (Line 6/Line 10)	0.4621%	

Plant Allocation Factor

12	Total Transmission Investment	2,914,018	Line 2
13	<i>plus Transmission-Related General Plant (Line 2 of Wkst. 3)</i>	27,207	Worksheet 3, Line 2
14	<i>= Revised Numerator (Line 12 + Line 13)</i>	2,941,225	
15	Total Plant in Service	39,273,605	Page 8B, line 30 (g)
16	Percent Allocation (Line 14 / Line 15)	7.4891%	

Affiliated Company Wages and Salaries

Shading denotes an input

Line		Middleborough
"Affiliated" Transmission Wages and Salaries #560 - 573		
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11 = 1 thru 10	Total Transmission	0
12 = Total "Affiliated" Wages and Salaries		
Less "Affiliated" Administrative and General Salaries #920 - 935		
13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
21 = 13 thru 20		0
22 = 12 less 21	Total "Affiliated" less A&G	0

Middleborough Gas and Electric Department

Sheet: Worksheet 7

PTF Revenue Requirements
Worksheet 7 of 7

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	FERC Form 1	TOTAL	
			Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	332.(g); [332.1(g) for HWP]		\$415
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			\$2,971
	Pool PTF Paments			276,169
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	332.1(g); [332(g) for CL&P]		\$7,038
	345 kV Golden Hills-Mystic 349 line			0
	345 kV NH/MA border-Tewksbury 394 line	332(g)		\$2,131
NU	115 kV Read - Washington V148 line			
	345 kV 363, 369 and 394 Seabrook lines			\$2,014
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310 line	330.1(n)		3,992
	UI Substations	330.1(n)		
Seabrook	CMP	330.1(n)		159
				\$23,115
Total =			0	318,004

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

Sheet: Input Panel

NEPOOL Tariff Billing
NEPOOL Annual Transmission Revenue Requirements
per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3

Shading denotes an input

POST 96

Submitted on: 18-May-12

Revenue Requirements for (year): Calendar Year 2011

Customer: Middleborough Gas and Electric Department

Customer's NABs Number: 79

Name of Participant responsible for customer's billing: John Granahan

DUNs number of Participant responsible for customer's billing: 15-597-6665

	<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>
Total of Attachment F - Sections A through I =	<u>(a)</u>	<u>208,870 (f)</u>
Total of Attachment F - Section J - Support Revenue	<u>0 (b)</u>	<u>0 (g)</u>
Total of Attachment F - Section K - Support Expense	<u>(c)</u>	<u>0 (h)</u>
Total of Attachment F - Section (L through O)	<u>0 (d)</u>	<u>0 (i)</u>
Sub Total - Sum (A through I) - J + K + (L through O)	<u>0 (e)=(a)-(b)+(c)+(d)</u>	<u>208,870 (j)</u>
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:		<u>208,870 (k) = (e) + (j)</u>
Total of Attachment F - Section J - Pre-97 Support Revenue (from above)		<u>0 (b)</u>
Total of Attachment F - Section J - Post-96 Support Revenue (from above-)		<u>0 (g)</u>
Total of Attachment F - Section K - Post-96 Support Expense (from above)		<u>0 (h)</u>
Voting Share Total for Participant's R Value: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)		<u>208,870 (l)=(k)+(b)+(g)-(h)</u>

Calendar Year 2011

Shading denotes an input

		Attachment F		
		Reference	Middleborough	Reference
Line No.	I. INVESTMENT BASE	Section:		
1	Transmission Plant	(A)(1)(a)	1,370,897	Worksheet 3a, L10
2	General Plant	(A)(1)(b)	12,800	Worksheet 3a, L11
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3a, L14
4	Total Plant (Lines 1+2+3)		1,383,697	
5	Accumulated Depreciation	(A)(1)(d)	529,015	Worksheet 3a, L19
6	Accumulated Deferred Income Taxes	(A)(1)(e)	0	Worksheet 3a, L24
7	Loss On Reacquired Debt	(A)(1)(f)	0	Worksheet 3a, L26
8	Other Regulatory Assets	(A)(1)(g)	0	Worksheet 3a, L32
9	Net Investment (Line 4-5-6+7+8)		854,682	
10	Prepayments	(A)(1)(h)	0	Worksheet 3a, L34
11	Materials & Supplies	(A)(1)(i)	0	Worksheet 3a, L36
12	Cash Working Capital	(A)(1)(j)	6,487	Worksheet 3a, 44
13	Total Investment Base (Line 9+10+11+12)		861,169	
II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	68,894	Worksheet 2a, E56
15	Depreciation Expense	(B)	69,159	Worksheet 4a, L12
16	Amortization of Loss on Reacquired Debt	(C)	0	Worksheet 4a, L14
17	Investment Tax Credit	(D)	0	Worksheet 4a, L16
18	Property Tax Expense	(E)	18,919	Worksheet 4a, L21
19	Payroll Tax Expense	(F)	0	Worksheet 4a, L42
20	Operation & Maintenance Expense	(G)	43,838	Worksheet 4a, L29
21	Administrative & General Expense	(H)	8,060	Worksheet 4a, L40
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	0	Worksheet 7, E51
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	0	
28	Transmission Rents Received from Electric Property	(O)	0	
29	Total Revenue Requirements (Line 14 thru 28)		208,870	

Middleborough Gas and Electric Department

Annual Revenue Requirements - 2012

Calendar Year 2011

Shading denotes an input

	CAPITALIZATION 12/31/2006	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 109,845,000	100.00%	8.00%	8.00%	
PREFERRED STOCK	0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	0	0.00%	0.00%	0.00%	0.00%
TOTAL INVESTMENT RETURN	\$ 109,845,000	100.00%		8.00%	0.00%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0800

(b) Federal Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / \text{Federal Income Tax Rate}}{1} \right) \times \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}}$$

=
$$\left(\frac{0.0000 + \left(\frac{0 + 0}{861,169} \right)}{1} \right) \times \frac{0}{0}$$

= 0.0000000

(c) State Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / \text{Federal Income Tax}}{1} \right) \times \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}} \times \text{State Income Tax Rate}$$

=
$$\left(\frac{0.0000 + \left(\frac{0 + 0}{861,169} \right)}{1} \right) \times \frac{0.0000000}{0} \times 0$$

= 0.0000000

(a)+(b)+(c) **Cost of Capital Rate** = 0.0800000

(PTF)

INVESTMENT BASE	\$ 861,169	From Worksheet 1
x Cost of Capital Rate	0.0800000	
= Investment Return and Income Taxes	<u>68,894</u>	To Worksheet 1

Middleborough Gas and Electric Department

Calendar Year 2011

Shading denotes an input

Line No.		(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Mass DTE AR Reference for col (1)
	<u>Transmission Plant</u>						
1	Transmission Plant	\$ 2,914,018		2,914,018		1,370,897	Worksheet 5, E12 Page 8B line 29(g)
2	General Plant	\$ 5,887,657	0.4621% (a)	27,207	47.0449%	12,800	
3	Total (line 1+2)			2,941,225		1,383,697	
4	<u>Transmission Plant Held for Future Use</u>	0		0	47.0449%	0	None known
	<u>Transmission Accumulated Depreciation</u>						
5	Transmission Accum. Depreciation	1,106,486		1,106,486	47.0449%	520,545	Page 8A, line 31(g) less Page 16, line 31(g)
6	General Plant Accum.Depreciation	3,896,419	0.4621% (a)	18,005	47.0449%	8,470	Page 8B, line 29(g) less
7	Total (line 5+6)			1,124,491		529,015	Page 17, line 29(g)
	<u>Transmission Accumulated Deferred Taxes</u>						
8	Accumulated Deferred Taxes (281-283)	0	7.5405% (c)	0	47.0449%	0	None known
9	Accumulated Deferred Taxes (190)	0	7.5405% (c)	0	47.0449%	0	None known
10	Total (line 8+9)			0		0	
11	<u>Transmission loss on Reacquired Debt</u>	0	7.5405% (c)	0	47.0449%	0	None known
	<u>Other Regulatory Assets</u>						
12	FAS 106	0	0.4621% (a)	0	47.0449%	0	None known
13	FAS 109	0	7.5405% (c)	0	47.0449%	0	None known
14	Other Regulatory Liabilities (254.DK)	0	7.5405% (c)	0	47.0449%	0	
15	Total (line 12+13+14)	0		0		0	
16	<u>Transmission Prepayments</u>	0	0.4621% (a)	0	47.0449%	0	Page 10, Line 26 MA DTE
17	<u>Transmission Materials and Supplies</u>	0	0.4621%	0	47.0449%	0	Page 10, Line 24 MA DTE
	<u>Cash Working Capital</u>						
18	Operation & Maintenance Expense					43,838	Worksheet 1, Line 20
20	Administrative & General Expense					8,060	Worksheet 1, Line 21
21	Transmission Support Expense					0	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					51,898	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					6,487	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

Middleborough Gas and Electric Department

Calendar Year 2011

Shading denotes an input		(2)	(4)			
Line No.	(1) Total	Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Mass DTE AR Reference for col (1)
<u>Depreciation Expense</u>						
1	145,701		145,701	47.0449%	68,545	Page 16, line 31(d)
2	282,539	0.4621% (a)	1,306	47.0449%	614	Page 17, line 29(d)
3			147,007		69,159	
4	0	7.5405% (c)	0	47.0449%	0	None known
5	0	7.5405% (c)	0	47.0449%	0	None known
<u>Property Taxes *</u>						
6	502,533	0.075405	37,894	47.0449%	17,827	Page 21, line 33 (b)
7	502,533	0.4621% (a)	2,322	47.0449%	1,092	Page 21, line 33 (b)
8			40,216		18,919	
<u>Transmission Operation and Maintenance</u>						
9	3,373,917		3,373,917	0.470449	1,587,256	Page 40, line 50(b)
10	3,280,734		3,280,734	0.470449	1,543,418	Page 40, line 38(b)
11	0		0	0.470449	0	Page 40, line 34(b)
12	0		0	0.470449	0	Page 40, line 35(b) 40(b)
13	93,183		93,183	47.0449%	43,838	
<u>Transmission Administrative and General</u>						
14	3,753,341					Page 42, line 5(b)
15	1					Page 41, line 47(b)
16	0					Page 41, line 50(b)
17	45,994					assumed none
18	3,707,346	0.4621% (a)	17,132	47.0449%	8,060	
19	1	7.5405% (c)	0	47.0449%	0	
20	0	7.5405% (c)	0	47.0449%	0	
21	0	7.5405% (c)	0	47.0449%	0	
22	3,707,347		17,132		8,060	
23	0	0.4621% (a)	0	47.0449%	0	Per company workpapers

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

Shading denotes an input

Calendar Year 2011

Line No.			Mass DTE AR Reference
	<u>PTF Transmission Plant Allocation Factor</u>	Middleborough	
1	PTF Transmission Investment	1,370,897	Per Company Workpapers
2	Total Transmission Investment	2,914,018	Page 8A, line 31(g)
3	Percent Allocation (Line 1/Line 2)	47.0449%	
	<u>Transmission Wages and Salaries Allocation Factor</u>		
4	Direct Transmission Wages and Salaries	13,775	See MGED General Ledger
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 of 7
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	13,775	
7	Total Wages and Salaries	3,289,546	Page 42, line 24 (c)
8	Administrative and General Wages and Salaries	308,472	Page 41, line 43(b)
9	Affiliated Company Wages and Salaries less A&G	0	Worksheet 6
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	2,981,074	
11	Percent Allocation (Line 6/Line 10)	0.4621%	
	<u>Plant Allocation Factor</u>		
12	Total Transmission Investment	2,914,018	Line 2
13	plus Transmission-Related General Plant (Line 2 of Wkst. 3)	47,416	Worksheet 3, Line 2
14	= Revised Numerator (Line 12 + Line 13)	2,961,434	
15	Total Plant in Service	39,273,605	Page 8B, line 30 (g)
16	Percent Allocation (Line 14 / Line 15)	7.5405%	

Affiliated Company Wages and Salaries

 Shading denotes an input

Calendar Year 2011

<u>Line</u>		<u>Middleborough</u>
"Affiliated" Transmission Wages and Salaries #560 - 573		
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11 = 1 thru 10	Total Transmission	0
12 = Total "Affiliated" Wages and Salaries		0
Less "Affiliated" Administrative and General Salaries #920 - 935		
13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
21 = 13 thru 20		0
22 = 12 less 21	Total "Affiliated" less A&G	0

Middleborough

PTF Revenue Requirements

Sheet: Worksheet 7

Calendar Year 2011

Worksheet 7 of 7

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	FERC Form 1	TOTAL	
			Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	332.(g); [332.1(g) for HWP]		0
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			0
	Comerford 115 kV Substation			
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	332.1(g); [332(g) for CL&P]		0
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 394 line	332(g)		0
	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			0
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310 line	330.1(n)		
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
Seabrook				0
Total =			0	0

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

ISO Tariff Billing
ISO Annual Transmission Revenue Requirements
per Tariff Attachment F and ISO Agreement Part 2, Section 6.3

Shading denotes an input

Submitted on:	
Revenue Requirements for (year):	Calendar Year 2011
Rates Effective for the Period:	June 2012
Through:	May 2013
Customer:	New England Power Company
Customer's NABs Number:	
Name of Participant responsible for customer's billing:	
DUNS number of Participant responsible for customer's billing:	

	<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>
Total of Attachment F - Sections A through I	<u>\$100,751,946</u> ^(a)	<u>\$131,640,727</u> ^(f)
Total of Attachment F - Section J - Support Revenue	<u>\$5,663,545</u> ^(b)	<u>\$0</u> ^(g)
Total of Attachment F - Section K - Support Expense	<u>\$723,254</u> ^(c)	<u>\$0</u> ^(h)
Total of Attachment F - Section (L through O)	<u>(\$509,692)</u> ^(d)	<u>(\$1,188,346)</u> ⁽ⁱ⁾
Sub Total - Sum (A through I) - J + K + (L through O)	<u>\$95,301,964</u> ^{(e)=(a)-(b)+(c)+(d)}	<u>\$130,452,381</u> ^(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	<u>N/A</u>	<u>\$37,048,813</u> ^(k)
Annual True-up (per Attachment C to Attachment F Implementation Rule)	<u>\$14,128,004</u> ^(l)	<u>(\$3,409,701)</u> ^(m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)	<u>\$109,429,967</u> ^{(n)=(e)+(l)}	<u>\$164,091,494</u> ^{(o)=(j)+(k)+(m)}
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements & Post-96 Revenue Requirements Subtotals, Forecasted Revenue Requirements and True-ups (including interest)		<u>\$273,521,461</u> ^{(p) = (n) + (o)}

New England Power Company
Transmission Revenue Requirements of PTF Facilities
2011 True-up

		PRE 97	POST 1996
I. <u>ANNUAL TRUE-UP PER ROE COMPLIANCE WITH FERC ROE ORDER</u>			
1	Transmission Revenue Requirements (as billed)	\$81,629,570	\$133,752,124
2	True-up 2011 Actual Annual RR	95,301,964	130,452,381
3	(Over)/Under (Line 2 - Line 1)	13,672,394	(3,299,743)
4	Per Month (Line 3/12)	1,139,366	(274,979)
5	Total Rate Year (Over)/Under	\$ 13,672,394	\$ (3,299,743)

New England Power Company
FERC Interest Calculation associated with Under / (Over)
Transmission Revenue Requirements of PTF Facilities

Pre 97	Undercollection/(Overcollection)
Post 96	\$13,672,394
	(\$3,299,743)

Initial Billing Period	PRE 97 Balance	POST 1996 Balance	FERC Monthly Interest Rate	PRE 97 Interest	POST 1996 Interest
June 2011	\$ 13,672,394	\$ (3,299,743)	0.27%	\$ 36,915	\$ (8,909)
July 2011	13,709,309	(3,308,652)	0.27%	37,015	(8,933)
August 2011	13,709,309	(3,308,652)	0.28%	38,386	(9,264)
September 2011	13,709,309	(3,308,652)	0.27%	37,015	(8,933)
October 2011	13,821,725	(3,335,783)	0.28%	38,701	(9,340)
November 2011	13,821,725	(3,335,783)	0.27%	37,319	(9,007)
December 2011	13,821,725	(3,335,783)	0.28%	38,701	(9,340)
January 2012	13,936,446	(3,363,470)	0.28%	39,022	(9,418)
February 2012	13,936,446	(3,363,470)	0.26%	36,235	(8,745)
March 2012	13,936,446	(3,363,470)	0.28%	39,022	(9,418)
April 2012	14,050,725	(3,391,050)	0.27%	37,937	(9,156)
May 2012	14,050,725	(3,391,050)	0.28%	39,342	(9,495)
Total Interest				\$ 455,610	\$ (109,958)
True-Up				13,672,394	\$ (3,299,743)
Total TU & Interest				\$ 14,128,004	\$ (3,409,701)

ISO Tariff Billing
ISO Annual Transmission Revenue Requirements
per Tariff Attachment F and ISO Agreement Part 2, Section 6.3

Shading denotes an input

Submitted on: _____

Revenue Requirements for (year): Calendar Year 2011

Rates Effective for the Period:
Through: June 2012
May 2013

Customer: New England Power Company

Customer's NABs Number: _____

Name of Participant responsible for customer's billing: _____

DUNS number of Participant responsible for customer's billing: _____

	<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>
Total of Attachment F - Sections A through I	<u>\$100,751,946</u> ^(a)	<u>\$131,640,727</u> ^(f)
Total of Attachment F - Section J - Support Revenue	<u>\$5,663,545</u> ^(b)	<u>\$0</u> ^(g)
Total of Attachment F - Section K - Support Expense	<u>\$723,254</u> ^(c)	<u>\$0</u> ^(h)
Total of Attachment F - Section (L through O)	<u>(\$509,692)</u> ^(d)	<u>(\$1,188,346)</u> ⁽ⁱ⁾
Sub Total - Sum (A through I) - J + K + (L through O)	<u>\$95,301,964</u> ^{(e)=(a)-(b)+(c)+(d)}	<u>\$130,452,381</u> ^(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	<u>N/A</u>	<u>\$37,048,813</u> ^(k)
Annual True-up (per Attachment C to Attachment F Implementation Rule)	<u>N/A</u> ^(l)	<u>N/A</u> ^(m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)	<u>\$95,301,964</u> ^{(n)=(e) + (l)}	<u>\$167,501,195</u> ^{(o)=(j)+(k)+(m)}
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:		<u>\$262,803,158</u> ^{(p) = (n) + (o)}

New England Power Company
Annual Revenue Requirements of PTF Facilities
For Costs in 2011

PRE-1997

Shading denotes an input

		Attachment F		
I. <u>INVESTMENT BASE</u>		Reference	NEP	Reference
Line No.		Section:		
1	Transmission Plant	(A)(1)(a)	\$337,128,880	Worksheet 3, line 1&2 column 5
2	General Plant	(A)(1)(b)	\$1,403,019	Worksheet 3, line 3 column 5
3	Plant Held For Future Use	(A)(1)(c)	\$225,863	Worksheet 3, line 5 column 5
4	Total Plant (Lines 1+2+3)		\$338,757,762	
5	Accumulated Depreciation	(A)(1)(d)	(\$77,684,122)	Worksheet 3, line 8 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	(\$76,548,029)	Worksheet 3, line 11 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	\$92,130	Worksheet 3, line 12 column 5
8	Other Regulatory Assets	(A)(1)(g)	\$9,378,217	Worksheet 3, line 16 column 5
9	Net Investment (Line 4+5+6+7+8)		\$193,995,958	
10	Prepayments	(A)(1)(h)	\$30,440	Worksheet 3, line 17 column 5
11	Materials & Supplies	(A)(1)(i)	\$840,715	Worksheet 3, line 18 column 5
12	Cash Working Capital	(A)(1)(j)	\$1,745,404	Worksheet 3, line 25 column 5
13	Total Investment Base (Line 9+10+11+12)		\$196,612,517	
II. <u>REVENUE REQUIREMENTS</u>				
14	Investment Return and Income Taxes	(A)	\$25,081,721	Worksheet 2
15	Depreciation Expense	(B)	\$7,642,645	Worksheet 4, line 3, column 5
16	Amortization of Loss on Reacquired Debt	(C)	\$61,120	Worksheet 4, line 4, column 5
17	Investment Tax Credit	(D)	(\$86,769)	Worksheet 4, line 5, column 5
18	Property Tax Expense	(E)	\$5,971,199	Worksheet 4, line 6, column 5
19	Payroll Tax Expense	(F)	\$498,203	Worksheet 4, line 22, column 5
20	Operation & Maintenance Expense	(G)	\$7,663,396	Worksheet 4, line 11, column 5
21	Administrative & General Expense	(H)	\$6,299,838	Worksheet 4, line 21, column 5
22	Transmission Related Integrated Facilities Charge	(I)	\$47,620,594	Attachment 4, line 6
23	Transmission Support Revenue	(J)	(\$5,663,545)	Worksheet 6
24	Transmission Support Expense	(K)	\$723,254	Worksheet 6
25	Transmission Related Expense from Generators	(L)	\$0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	\$0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(\$242,951)	Attachment 7
28	Transmission Rents Received from Electric Property	(O)	(\$266,741)	Attachment 6
29	Total Revenue Requirements (Line 14 thru 28)		\$95,301,964	

New England Power Company
Annual Revenue Requirements
For Costs in 2011

Shading denotes an input

	CAPITALIZATION 12/31/2011	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$410,350,000	35.45%	1.18%	0.42%	
PREFERRED STOCK	\$1,111,700	0.10%	6.02%	0.01%	0.01%
COMMON EQUITY	\$746,206,523	64.46%	11.64%	7.50%	7.50%
TOTAL INVESTMENT RETURN	\$1,157,668,223	100.00%		7.93%	7.51%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0793

(b) Federal Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / \text{Federal Income Tax Rate}}{1} \right) \times \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}}$$

=
$$\left(\frac{0.0751 + \left(\frac{(\$86,769) + \$249,383}{\$196,612,517} \right) / 0.35}{1} \right) \times \frac{0.35}{0.35}$$

= 0.0408838

(c) State Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / \text{Federal Income Tax Rate}}{1} \right) + \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}}$$

=
$$\left(\frac{0.0751 + \left(\frac{(\$86,769) + \$249,383}{\$196,612,517} \right) / 0.0408838}{1} \right) + \frac{0.0408838}{0.059466}$$

= 0.0073855

(a)+(b)+(c) Cost of Capital Rate = 0.1275693

	<u>(PTF)</u>	
INVESTMENT BASE	\$196,612,517	From Worksheet 1
x Cost of Capital Rate	0.1275693	
= Investment Return and Income Taxes	<u>\$25,081,721</u>	To Worksheet 1

New England Power Company

Shading denotes an input

Line No.		(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Source Reference
1	Transmission Plant					\$350,215,608	Attachment 1, Page 1
2	Less: Plant Assoc. HVDC Leases					(\$13,086,728)	Attachment 2
3	General Plant	\$6,396,486	99.8099% (a)	\$6,384,326	21.9760% (b)	\$1,403,019	FERC Form 1 Page 207.99g
4	Total (line 1+2+ 3)			\$6,384,326		\$338,531,899	
5	Transmission Plant Held for Future Use	\$1,027,771		\$1,027,771	21.9760% (b)	\$225,863	FERC Form 1 Page 214.2,4,9
	Transmission Accumulated Depreciation						
6	Transmission Accumulated Depreciation	(\$348,750,683)		(\$348,750,683)	21.9760% (b)	(\$76,641,450)	FERC Form 1 Page 219.25
7	General Plant Accumulated Depreciation	(\$4,753,633)	99.8099% (a)	(\$4,744,596)	21.9760% (b)	(\$1,042,672)	FERC Form 1 Page 219.28
8	Total (line 6+ 7)			(\$353,495,279)		(\$77,684,122)	
	Transmission Accumulated Deferred Taxes						
9	Accumulated Deferred Taxes (281-283)	(\$402,325,609)	99.2997% (c)	(\$399,508,123)	21.9760% (b)	(\$87,795,905)	FERC Form 1 Page 113.62-64
10	Accumulated Deferred Taxes (190)	\$51,543,505	99.2997% (c)	\$51,182,546	21.9760% (b)	\$11,247,876	FERC Form 1 Page 111.82
11	Total (line 9+ 10)			(\$348,325,577)		(\$76,548,029)	
12	Transmission Loss on Reacquired Debt	\$419,230	100.0000%	\$419,230	21.9760% (b)	\$92,130	FERC Form 1 Page 111.81c
	Other Regulatory Assets						
13	FAS 106	\$0	99.8099% (a)	\$0	21.9760% (b)	\$0	
14	FAS 109 (Asset Account 182.3)	\$42,674,813	100.0000%	\$42,674,813	21.9760% (b)	\$9,378,217	FERC Form 1 Page 232.7f
15	FAS 109 (Liability Account 254)	\$0	100.0000%	\$0	21.9760% (b)	\$0	FERC Form 1 Page 278
16	Total (line 13+14+ 15)	\$42,674,813		\$42,674,813		\$9,378,217	
17	Transmission Prepayments	\$138,779	99.8099% (a)	\$138,515	21.9760% (b)	\$30,440	FERC Form 1 Page 111.57c
18	Transmission Materials and Supplies	\$3,825,605		\$3,825,605	21.9760% (b)	\$840,715	FERC Form 1 Page 227.8c
19	Cash Working Capital						
20	Operation & Maintenance Expense					\$7,663,396	Worksheet 1, Line 20
21	Administrative & General Expense					\$6,299,838	Worksheet 1, Line 21
22	Transmission Support Expense					\$0	Worksheet 6
23	Subtotal (line 20+21+22)					\$13,963,234	
24						0.1250	x 45 / 360
25	Total (line 23 * line 24)					\$1,745,404	

(a) Worksheet 5 Line 11

(b) Worksheet 5 Line 3

(c) Worksheet 5 Line 16

New England Power Company

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Source Reference for Col (1)
<u>Depreciation Expense</u>						
1	\$34,416,139		\$34,416,139	21.9760% (b)	\$7,563,291	FERC Form 1 Page 336.7b
2	\$361,782	99.8099% (a)	\$361,094	21.9760% (b)	\$79,354	FERC Form 1 Page 336.10b
3			\$34,777,233		\$7,642,645	
<u>Amortization of Loss on Reacquired Debt</u>						
4	\$278,121	100.0000%	\$278,121	21.9760% (b)	\$61,120	FERC Form 1 Page 117.64c
<u>Amortization of Investment Tax Credits</u>						
5	(\$394,836)	100.0000%	(\$394,836)	21.9760% (b)	(\$86,769)	FERC Form 1 Page 266.8f - Footnote (f)
<u>Property Taxes</u>						
6	\$27,171,454	100.0000%	\$27,171,454	21.9760% (b)	\$5,971,199	FERC Form 1 Page 263.10,17,23,28i - Footnote (e)
<u>Transmission Operation and Maintenance</u>						
7	\$61,295,709		\$61,295,709	21.9760% (b)	\$13,470,345	FERC Form 1 Page 321.112b
8	\$14,532,110		\$14,532,110	21.9760% (b)	\$3,193,576	FERC Form 1 Page 321.96b
9	\$11,891,943		\$11,891,943	21.9760% (b)	\$2,613,373	FERC Form 1 Page 321.84-92b less 87b
10	\$0		\$0		\$0	FERC Form 1 Page 321.93b & .98b
11	\$34,871,656		\$34,871,656	21.9760% (b)	\$7,663,396	
<u>Transmission Administrative and General</u>						
12	\$30,296,960					FERC Form 1 Page 323.197b
13	(\$135,569)					FERC Form 1 Page 323.185b
14	\$4,168,438					FERC Form 1 Page 323.189b
15	\$0					FERC Form 1 Page 323.191b
16	\$26,264,091	99.8099% (a)	\$26,214,163	21.9760% (b)	\$5,760,824	
17	(\$135,569)	99.2997% (c)	(\$134,620)	21.9760% (b)	(\$29,584)	Line 13
18	\$2,605,606	99.2997% (c)	\$2,587,359	21.9760% (b)	\$568,598	Attachment 5 Line 6
19	\$0		\$0	21.9760% (b)	\$0	Line 15
20	\$0		\$0	21.9760% (b)	\$0	FERC Form 1 Page 350.18c
21	\$28,734,128		\$28,666,902		\$6,299,838	
<u>Payroll Tax Expense</u>						
22	\$2,271,348	99.8099% (a)	\$2,267,030	21.9760% (b)	\$498,203	FERC Form 1 Page 263.3,4i - Footnote (d)

(d) Payroll taxes FERC Form 1, page 263.i

Federal Unemployment	\$9,327
FICA	\$2,262,021
Payroll Taxes	\$0
State Unemployment	\$0
Total	\$2,271,348

(e) Property Taxes FF1, Page 263i

Massachusetts	\$23,571,202
New Hampshire	\$2,662,307
Vermont	\$786,615
Maine	\$0
Rhode Island	\$151,330
Connecticut	\$0
	\$27,171,454

(a) Worksheet 5 Line 11

(b) Worksheet 5 Line 3

(c) Worksheet 5 Line 16

(d) Transmission Only - Payroll Taxes - Specifically identified in FERC Form 1

(e) Transmission Only - Property Taxes - Specifically Identified in FERC Form 1

(f) Transmission Only - Amortization of ITC - Specifically Identified in FERC Form 1

** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments.

Shading denotes an input

Line No.			Source Reference
	<u>PTF Transmission Plant Allocation Factor</u>	NEP	
1	PTF Transmission Investment	\$350,215,608	Attachment 1, Page 1
2		\$1,593,625,753	FERC Form 1 Page 207.58g - Page 200.4b
3	Percent Allocation (Line 1/Line 2)	<u>21.9760%</u>	
	<u>Transmission Wages and Salaries Allocation Factor</u>		
4	Direct Transmission Wages and Salaries	\$0	FERC Form 1 Page 354.14b
5	Affiliated Company Transmission Wages and Salaries	\$23,467,616	General Ledger Query
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	\$23,467,616	
7	Total Wages and Salaries	\$0	FERC Form 1 Page 354.28b
8	Administrative and General Wages and Salaries	\$0	FERC Form 1 Page 354.27b
9	Affiliated Company Wages and Salaries less A&G	\$23,512,307	General Ledger Query
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	\$23,512,307	
11	Percent Allocation (Line 6/Line 10)	<u>99.8099%</u>	
	<u>Plant Allocation Factor</u>		
12	Total Transmission Investment	\$1,593,625,753	Line 2
13	plus Transmission-Related General Plant	\$6,384,326	Worksheet 3, Line 3, Column 3
14	= Revised Numerator (Line 12 + Line 13)	<u>\$1,600,010,079</u>	
15	Total Plant in Service	\$1,611,293,575	FERC Form 1 Page 207.104g - Page 200.4b
16	Percent Allocation (Line 14 / Line 16)	<u>99.2997%</u>	

Shading denotes input

**New England Power Company
Pre-97 RNs Revenue Requirements
For Test Year Ended 12/31/2011**

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	FERC Form 1 Reference	TOTAL	
			Revenues	Expenses
			(a)	(b)
NSTAR	HQ Phase II - AC in MA	Pg 332 Line 5 Col (g)		\$102,578
	345 kV "stabilizer" 342 Line	Pg 332 Line 3 Col (g)		(446)
	345 kV Switch Tap Bridge - Station 451 Whitman	Pg 332 Line 13 Col (g)		\$774
	Bell Rock Road	Page 330.5 Line 12 Col (n)	\$38,953	
	Boston-Edison [345 kV Sandy-Tewksbury 337 line-345kV Tewksbury-Woburn 338 Line]	Page 330 Line 4 Col (n)	\$61,463	
	Boston-Edison [115 kV Tewksbury - Woburn M139 line - 115kV Tewksbury-Woburn N140 Line]	Page 330 Line 3 Col (n)	\$11,594	
	Boston Edison -345 kV Golden Hills-Mystic 349 Line	Page 330 Line 2 Col (n)	\$47,313	
	Boston Edison -345 kV NH/MA border - Tewksbury 394 Line (Seabrook)	Page 330.1 Line 8 Col (n)	\$423,318	
NU	Public Service Co. -Moore 115 kV Substation	Page 330.1 Line 5 Col (n)	\$13,319	
NEP	Chester SVC	Transmission Billing		\$620,348
	HQ Phase II - AC in MA	Page 330 Line 11 Col (n)	\$5,027,675	
VT Elec Co.	Comerford 115 kV Substation	Page 330.1 Line 12 Col (n)	\$39,910	
		Totals	\$5,663,545	\$723,254

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 22, Column 5)

\$0

Shading denotes an input

New England Power Company
2011 Informational Filing
PTF Plant Allocation

				Percent Pre/Post
1	2010	Pre-1997 PTF Transmission Plant	\$351,352,992	
2	2010	Post-1996 PTF Transmission Plant	\$725,670,117	
3	2011	Additions/Retirements	\$89,719,314	
4	2011	Pre-1997 PTF Transmission Plant	\$350,215,608	30.02%
5	2011	Post-1996 PTF Transmission Plant	\$816,526,816	69.98%
6	2011	Total PTF Transmission Plant	\$1,166,742,423	100.00%

Sources:

- 1 PTF Plant Reports for previous year
- 2 PTF Plant Reports for previous year
- 3 Line 6 - Line 1 + Line 2
- 4 PTF Plant Reports for current year
- 5 PTF Plant Reports for current year
- 6 Line 4 + 5

Shading denotes an input

GROSS PLANT ASSOC. WITH HVDC LEASES
2011

LINE NO		(HVDC) NHH/NEH LEASE
1	Gross Plant Value Comerford Station to Tewksbury Line	\$14,269,187
	<u>Allocation</u>	
2	Miles used by NHH (a)	224
3	Total miles at Comerford Station	253
4	Percentage of Total Gross Plant leased by NHH (a)	89%
5	Total Gross Plant leased by NHH (a)	\$12,699,576
6	Total Land from Sandy Pond to New Hampshire	\$1,106,146
7	HVDC lines occupy 35% of Right of Way	35%
8	Total Land leased by NEH (a)	\$387,151
9	Total NEP Gross Plant leased by HVDC to be excluded from PTF Revenue requirement	\$13,086,728

Source:

- 1 FERC Form 1, Page 422.1-423.1, Lines 5 + 16 col (l)
- 2 Total miles used per lease agreement
- 3 FERC Form 1, Page 422.1 Lines 5 + 16 col (f)
- 4 Line 2 / Line 3
- 5 Line 1 * Line 4
- 6 FERC Form 1, Page 422-423, Line 15
- 7 Percentage per lease agreement
- 8 Line 6 * Line 7
- 9 Line 5 + Line 8

Note:

- (a) NEH and NHH are acronyms for two of the three "Hydro Companies, New England Hydro Transmission (NEH) Electric Company, New England Electric Transmission Corporation, and New England Hydro Transmission Electric Company, Inc. (NHH)" which own and lease the HVDC interconnection facilities to the participants to the NEPOOL HVDC agreements.

New England Power Company
Determination of Book Depreciation on Equity AFUDC

		<u>2011</u>
1	Total Current Year Book Depreciation on Equity AFUDC	\$1,137,510
2	Less: Specifically Identified Transmission-Related	
	Tewksbury Line	\$54,708
	Hydro-Quebec	\$23,543
	Montaup Transmission Only 1990 - 1999	\$9,713
	1998 Transmission	\$13,959
	1999 Transmission	\$42,457
	2000 Transmission	(\$8,299)
	2001 Transmission	\$23,561
	2002 Transmission	\$8,889
	2003 Transmission	\$16,500
	2004 Transmission	\$15,518
	2005 Transmission	\$49,757
	2006 Transmission	\$64,352
	2007 Transmission	\$42,418
	2008 Transmission	\$57,508
	2009 Transmission	\$98,437
	2010 Transmission	\$79,948
	2011 Transmission	\$157,122
		\$750,091
3	Total Unidentified Book Depreciation on Equity AFUDC	\$387,419
4	Plant Allocator Factor	99.2997%
5	Allocated Transmission Related Book Depreciation on Equity AFUDC	\$384,706
6	Plus: Specifically Identified Transmission-Related Equity AFUDC	<u>\$750,091</u>
7	Total Transmission-Related Equity AFUDC	\$1,134,797
8	Pre-97 PTF Allocation Factor	21.9760%
9	Transmission-Related Equity AFUDC	\$249,383

Sources:

- 1 & 2 Transmission Rates includes \$9,713 from Montaup
- 3 Line 1 - Line 2
- 4 Worksheet 5 - PTF Plant Allocation Factor
- 5 Line 3 * Line 4
- 6 Line 2
- 7 Line 5 + Line 6
- 8 Worksheet 5 - Pre-97 PTF Allocation Factor
- 9 Line 7 * Line 8

Shading denotes an input

New England Power Company
Determination of the PTF Related Integrated Facilities Charges

	<u>Narragansett</u> <u>2011</u>	<u>MECO</u> <u>2011</u>
1 Total Integrated Facilities Charges	\$60,868,519	\$8,564,781
2 Total 2011 PTF Property	\$228,545,943	\$23,325,823
3 Total Transmission Plant in 2011	\$321,180,057	\$46,378,064
4 NECO or MECO PTF Plant Allocator	71.16%	50.29%
5 PTF Related Integrated Facilities Charge	\$43,312,942	\$4,307,652
6 Total Integrated Facilities		<u>\$47,620,594</u>

Source:

- 1 FF1 Page 330.4 Lines 13 & 14 Col (n)
- 2 PowerPlant Reports
- 3 FF1 Page 207 Line 58 (g)
- 4 Line 2 / Line 3
- 5 Line 1 * Line 4
- 6 Line 5 Totals for Narragansett and Massachusetts Electric

Shading denotes an input

Attachment 5

New England Power Company
Development of 2011 Regulatory Commission Expense

<u>Line</u> <u>No.</u>		<u>2011</u>	<u>Source</u>
1	Total Regulatory Commission Expense - NEP	\$4,168,438	FERC Form1 Page 350.46d
2	Less: New Hampshire PUC Assessment	\$78,276	FERC Form1 Page 350.2d
3	Less: Mass Emergency Fund	\$0	FERC Form1 Page 350.7d
4	Less Mass DPU Special Assessment	\$229,133	FERC Form1 Page 350.8d
5	Less: Utility Expenses	\$1,255,423	FERC Form1 Page 350.46c
6	Total Federal Assessments	\$2,605,606	Line 1 - (Line 2-5)

Transmission Rents Received from Electric Property
New England Power Company

	<u>2011</u>
Revenues	\$1,213,781
Plant Allocation Factor	100.00%
Transmission Allocated	\$1,213,781
PTF Allocation	21.9760%
Total PTF Revenue	\$266,741

Source: Peoplesoft Activities #454002, 454020 and 454024 - see Analysis for details

Revenue for Short-Term Transmission Service under the NEPOOL Tariff

New England Power Company

	<u>2011</u>
Revenues	\$809,392
Pre-97 PTF Percent	30.0165%
Total Pre-97 PTF Revenue	\$ 242,951

Source: Short Term Through and Out Revenues from ISO New England

ISO Tariff Billing
ISO Annual Transmission Revenue Requirements
per Tariff Attachment F and ISO Agreement Part 2, Section 6.3

Shading denotes an input

Submitted on:	
Revenue Requirements for (year):	Calendar Year 2011
Rates Effective for the Period:	June 2012
Through:	May 2013
Customer:	New England Power Company
Customer's NABs Number:	
Name of Participant responsible for customer's billing:	
DUNS number of Participant responsible for customer's billing:	

	<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>
Total of Attachment F - Sections A through I	<u>\$100,751,946</u> ^(a)	<u>\$131,640,727</u> ^(f)
Total of Attachment F - Section J - Support Revenue	<u>\$5,663,545</u> ^(b)	<u>\$0</u> ^(g)
Total of Attachment F - Section K - Support Expense	<u>\$723,254</u> ^(c)	<u>\$0</u> ^(h)
Total of Attachment F - Section (L through O)	<u>(\$509,692)</u> ^(d)	<u>(\$1,188,346)</u> ⁽ⁱ⁾
Sub Total - Sum (A through I) - J + K + (L through O)	<u>\$95,301,964</u> ^{(e)=(a)-(b)+(c)+(d)}	<u>\$130,452,381</u> ^(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	<u>N/A</u>	<u>\$37,048,813</u> ^(k)
Annual True-up (per Attachment C to Attachment F Implementation Rule)	<u>N/A</u> ^(l)	<u>N/A</u> ^(m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)	<u>\$95,301,964</u> ^{(n)=(e)+(l)}	<u>\$167,501,195</u> ^{(o)=(j)+(k)+(m)}
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements & Post-96 Revenue Requirements Subtotals, Forecasted Revenue Requirements and True-ups (including interest)		<u>\$262,803,158</u> ^{(p) = (n) + (o)}

New England Power Company
Annual Revenue Requirements of PTF Facilities
For Costs in 2011

POST-1996

Shading denotes an input

		Attachment F		
		Reference	NEP	Reference
I. INVESTMENT BASE		Section:		
Line No.				
1	Transmission Plant	(A)(1)(a)	\$816,526,816	Worksheet 5, line 1&2 column 5
2	General Plant	(A)(1)(b)	\$3,271,137	Worksheet 5, line 3 column 5
3	Plant Held For Future Use	(A)(1)(c)	\$526,599	Worksheet 5, line 5 column 5
4	Total Plant (Lines 1+2+3)		<u>\$820,324,552</u>	
5	Accumulated Depreciation	(A)(1)(d)	(\$181,120,376)	Worksheet 5, line 8 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	(\$178,471,576)	Worksheet 5, line 11 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	\$214,801	Worksheet 5, line 12 column 5
8	Other Regulatory Assets	(A)(1)(g)	\$21,865,294	Worksheet 5, line 16 column 5
9	Net Investment (Line 4+5+6+7+8)		<u>\$482,812,695</u>	
10	Prepayments	(A)(1)(h)	\$70,971	Worksheet 5, line 17 column 5
11	Materials & Supplies	(A)(1)(i)	\$1,960,125	Worksheet 5, line 18 column 5
12	Cash Working Capital	(A)(1)(j)	\$4,069,406	Worksheet 5, line 25 column 5
13	NEEWS CWIP	(A)(1)(k)	\$10,910,787	Worksheet 5, line 26 column 5
14	Total Investment Base (Line 9+10+11+12+13)		<u><u>\$499,823,984</u></u>	
II. REVENUE REQUIREMENTS				
15	Investment Return and Income Taxes	(A)	\$66,243,070	Worksheet 3
16	Depreciation Expense	(B)	\$17,818,811	Worksheet 6, line 3, column 5
17	Amortization of Loss on Reacquired Debt	(C)	\$142,501	Worksheet 6, line 4, column 5
18	Investment Tax Credit	(D)	(\$202,302)	Worksheet 6, line 5, column 5
19	Property Tax Expense	(E)	\$13,921,838	Worksheet 6, line 6, column 5
20	Payroll Tax Expense	(F)	\$1,161,558	Worksheet 6, line 22, column 5
21	Operation & Maintenance Expense	(G)	\$17,867,190	Worksheet 6, line 11, column 5
22	Administrative & General Expense	(H)	\$14,688,061	Worksheet 6, line 21, column 5
23	Transmission Related Integrated Facilities Charge	(I)	\$0	Attachment 4, line 6
24	Transmission Support Revenue	(J)	\$0	Worksheet 8
25	Transmission Support Expense	(K)	\$0	Worksheet 8
26	Transmission Related Expense from Generators	(L)	\$0	
27	Transmission Related Taxes and Fees Charge	(M)	\$0	
28	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(\$566,441)	Attachment 7
29	Transmission Rents Received from Electric Property	(O)	(\$621,905)	Attachment 6
30	Total Revenue Requirements (Line 14 thru 28)		<u><u>\$130,452,381</u></u>	

New England Power Company
Post 1996 Regional Network Service Revenue Requirement
For Test Year Ended 12/31/2011

Shading denotes an input

Line No.	Description	Attachment F Reference	Forecasted Amount \$	Reference
1	Forecasted Revenue Requirements for Forecasted Transmission Plant Additions (FTPA)		\$ 37,168,668	Line 6
2	Forecasted Revenue Requirements for Forecasted Transmission CWIP		\$119,855	Line 9
3	Forecasted Transmission Revenue Requirements		\$ 37,048,813	Line 1 + Line 2
4	Forecasted Revenue Requirements for Forecasted Transmission Plant Additions (FTPA)	Appendix C iv	\$237,573,000	Project Detail
5	Carrying Charge Factor (CCF)	Appendix C vi	15.64516%	Line 20
6	Forecasted Revenue Requirements for FTPA		\$ 37,168,668	Line 4 * Line 5
7	Forecasted New England Power Company (NEP) NEEWS CWIP (FNCWIP)	Appendix C xiii	\$ (851,389)	Project Detail
8	NEEWS NEP Cost of Capital Rate (NCOC)	Appendix C xiv	14.07756%	Workpaper 4
9	Forecasted Revenue Requirements for FNCWIP		\$ (119,855)	Line 7 * Line 8
Derivation of Carrying Charge (CCF)				
10	Investment Return and Income Taxes	(A)	\$62,349,242	Summary, Line 14
11	Depreciation Expense	(B)	17,818,811	Summary, Line 15
12	Amortization of Loss on Reacquired Debt	(C)	142,501	Summary, Line 16
13	Investment Tax Credit	(D)	(202,302)	Summary, Line 17
14	Property Tax Expense	(E)	13,921,838	Summary, Line 18
15	Payroll Tax Expense	(F)	1,161,558	Summary, Line 19
16	Operation & Maintenance Expense	(G)	17,867,190	Summary, Line 20
17	Administrative & General Expense	(H)	14,688,061	Summary, Line 21
18	Total Expenses (Lines 10 thru 17)		\$127,746,899	
19	PTF Transmission Plant	(A)(1)(a)	\$816,526,816	Summary, Line 1
20	Carrying Charge Factor (FTPA)		15.64516%	Line 18 / Line 19

New England Power Company
Annual Revenue Requirements
For Costs in 2011

Shading denotes an input

	CAPITALIZATION 12/31/2011	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$410,350,000	35.45%	1.18%	0.42%	
PREFERRED STOCK	\$1,111,700	0.10%	6.02%	0.01%	0.01%
COMMON EQUITY	\$746,206,523	64.45%	11.64%	7.50%	7.50%
TOTAL INVESTMENT RETURN	<u>\$1,157,668,223</u>	<u>100.00%</u>		<u>7.93%</u>	<u>7.51%</u>

Cost of Capital Rate=

(a) Weighted Cost of Capital	=	<u>0.0793</u>
(b) Federal Income Tax	=	((1 R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) x Federal Income Tax Rate Federal Income Tax Rate))
	=	((1 0.0751 + ((\$202,302) + \$581,812) / \$499,823,984) x 0.35 0.35))
	=	<u>0.0408473</u>
(c) State Income Tax	=	((1 R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax State Income Tax Rate)) * State Income Tax Rate
	=	((1 0.0751 + ((\$202,302) + \$581,812) / \$499,823,984) + 0.0408473 0.059466)) * 0.059466
	=	<u>0.0073789</u>
(a)+(b)+(c) Cost of Capital Rate	=	<u>0.1275262</u>

	<u>(PTF)</u>	
INVESTMENT BASE	\$499,823,984	From Worksheet 1
x Cost of Capital Rate	0.1275262	
= Investment Return and Income Taxes	<u>\$63,740,653</u>	To Worksheet 1
INVESTMENT BASE (Excluding NEEWS CWIP)	\$488,913,197	From Worksheet 1
x Cost of Capital Rate	0.1275262	
= Investment Return and Income Taxes	<u>\$62,349,242</u>	To Worksheet 2

Post 2003 PTF Investment Base w/ Incremental 100 bps:

Plant In-Service	\$ 327,705,145	From Attachment 1
Accumulated Depreciation	(71,715,328)	From Worksheets 5 & 7
Accumulate Deferred Income Taxes	(71,126,301)	From Worksheets 5 & 7
Total Post-2003 Investment	\$ 184,863,516	Calculated

Incremental ROE:	1.00%	0.00645	Calculated
Federal Income Taxes:		0.00347	Per Attachment F
State Income Taxes:		0.00063	Per Attachment F
Cost of Capital Rate		0.01054	
Incremental Return and Taxes on Post-2003 PTF Investment		\$ 1,948,885	

NEEWS In-Service w/ Incremental 125 bps:

New England Power NEEWS In-Service	\$ 55,119,725	Plant Accounting Records
Accumulated Depreciation	(12,062,457)	From Worksheets 3 & 5
Accumulate Deferred Income Taxes	(11,963,383)	From Worksheets 3 & 5
Total New England Power NEEWS Investment	\$ 31,093,885	Calculated

Incremental ROE:	1.25%	0.00806	Calculated
Federal Income Taxes:		0.00434	Per Attachment F
State Income Taxes:		0.00078	Per Attachment F
Cost of Capital Rate		0.01318	
Incremental Return and Taxes on NEEWS PTF Investment		\$ 409,751	

NEEWS Allocation Factor

Total Transmission Investment	\$1,593,625,753	Worksheet 7 Line 2
Total NEEWS In-Service - NEP	\$55,119,725	Plant Accounting Records
For Accumulated Depreciation	3.4588%	
NEEWS Allocation Factor	3.4588%	
Plant Allocation Factor	0.992997	Worksheet 7 Line 16
For Accumulated Deferred Income Taxes	3.4345%	

New England Power Company
Annual Revenue Requirements
For Costs in 2011

Shading denotes an input

	CAPITALIZATION 12/31/2011	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$410,350,000	35.45%	1.18%	0.42%	
PREFERRED STOCK	\$1,111,700	0.10%	6.02%	0.01%	0.01%
COMMON EQUITY	\$746,206,523	64.46%	12.89%	8.31%	8.31%
TOTAL INVESTMENT RETURN	\$1,157,668,223	100.00%		8.74%	8.32%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0874

(b) Federal Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / \text{Federal Income Tax Rate}}{1} \right) \times \frac{\text{Federal Income Tax Rate}}{0.35}$$

= 0.0452088

(c) State Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / \text{State Income Tax Rate}}{1} \right) \times \frac{\text{Federal Income Tax} + \text{State Income Tax Rate}}{0.059466}$$

= 0.0081668

(a)+(b)+(c) Cost of Capital Rate = 0.1407756

New England Power Company

Shading denotes an input							
Line No.		(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Source Reference for Col (1)
1	Transmission Plant					\$816,526,816	Attachment 1, Page 1
2	Less: Plant Assoc. HVDC Leases					\$0	Attachment 2
3	General Plant	\$6,396,486	99.8099% (a)	\$6,384,326	51.2370% (b)	\$3,271,137	FERC Form 1 page 207.99
4	Total (line 1+2+ 3)			\$6,384,326		\$819,797,953	
5	Transmission Plant Held for Future Use	\$1,027,771		\$1,027,771	51.2370% (b)	\$526,599	FERC Form 1 page 214.2,4,10
	Transmission Accumulated Depreciation						
6	Transmission Accumulated Depreciation	(\$348,750,683)		(\$348,750,683)	51.2370% (b)	(\$178,689,387)	FERC Form 1 page 219.25
7	General Plant Accumulated Depreciation	(\$4,753,633)	99.8099% (a)	(\$4,744,596)	51.2370% (b)	(\$2,430,989)	FERC Form 1 Page 219.28
8	Total (line 6+ 7)			(\$353,495,279)		(\$181,120,376)	
	Transmission Accumulated Deferred Taxes						
9	Accumulated Deferred Taxes (281-283)	(\$402,325,609)	99.2997% (c)	(\$399,508,123)	51.2370% (b)	(\$204,695,977)	FERC Form 1 page 113.62-64
10	Accumulated Deferred Taxes (190)	\$51,543,505	99.2997% (c)	\$51,182,546	51.2370% (b)	\$26,224,401	FERC Form 1 page 111.82
11	Total (line 9+ 10)			(\$348,325,577)		(\$178,471,576)	
12	Transmission Loss on Reacquired Debt	\$419,230	100.0000%	\$419,230	51.2370% (b)	\$214,801	FERC Form 1 Page 111.81c
	Other Regulatory Assets						
13	FAS 106	\$0	99.8099% (a)	\$0	51.2370% (b)	\$0	
14	FAS 109 (Asset Account 182.3)	\$42,674,813	100.0000%	\$42,674,813	51.2370% (b)	\$21,865,294	FERC Form 1 Page 232.6f
15	FAS 109 (Liability Account 254)	\$0	100.0000%	\$0	51.2370% (b)	\$0	FERC Form 1 Page 278
16	Total (line 13+14+ 15)	\$42,674,813		\$42,674,813		\$21,865,294	
17	Transmission Prepayments	\$138,779	99.8099% (a)	\$138,515	51.2370% (b)	\$70,971	FERC Form 1 Page 111.57c
18	Transmission Materials and Supplies	\$3,825,605		\$3,825,605	51.2370% (b)	\$1,960,125	FERC Form 1 Page 227.8c
19	Cash Working Capital						
20	Operation & Maintenance Expense					\$17,867,190	Worksheet 1, Line 20
21	Administrative & General Expense					\$14,688,061	Worksheet 1, Line 21
22	Transmission Support Expense					\$0	Worksheet 8
23	Subtotal (line 20+21+22)					\$32,555,251	
24						0.1250	x 45 / 360
25	Total (line 23 * line 24)					\$4,069,406	
26	NEEWS CWIP	\$10,910,787				\$10,910,787	Plant Accounting Records

(a) Worksheet 7 Line 11

(b) Worksheet 7 Line 3

(c) Worksheet 7 Line 16

New England Power Company

Shading denotes an input

Line No.	(1) Total (g)	Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Source Reference for Col (1)
<u>Depreciation Expense</u>						
1	\$34,416,139		\$34,416,139	51.2370%	\$17,633,797	FERC Form 1 Page 336.7b
2	\$361,782	99.8099% (a)	\$361,094	51.2370%	\$185,014	FERC Form 1 Page 336.10b
3			\$34,777,233		\$17,818,811	
<u>Amortization of Loss on Reacquired Debt</u>						
4	\$278,121		\$278,121	51.2370%	\$142,501	FERC Form 1 Page 117.64c
<u>Amortization of Investment Tax Credits</u>						
5	(\$394,835)		(\$394,835)	51.2370%	(\$202,302)	FERC Form 1 Page 266.8f - Footnote (f)
<u>Property Taxes</u>						
6	\$27,171,454		\$27,171,454	51.2370%	\$13,921,838	FERC Form 1 Page 263.10,17,23,28,31i - Footnote (e)
<u>Transmission Operation and Maintenance</u>						
7	\$61,295,709		\$61,295,709	51.2370%	\$31,406,082	FERC Form 1 Page 321.112b
8	\$14,532,110		\$14,532,110	51.2370%	\$7,445,817	FERC Form 1 Page 321.96b
9	\$11,891,943		\$11,891,943	51.2370%	\$6,093,075	FERC Form 1 Page 321.84-92b less 87b
10	\$0		\$0		\$0	FERC Form 1 Page 321.93b & .98b
11	\$34,871,656		\$34,871,656	51.2370%	\$17,867,190	
<u>Transmission Administrative and General</u>						
12	\$30,296,960					FERC Form 1 Page 323.197b
13	(\$135,569)					FERC Form 1 Page 323.185b
14	\$4,168,438					FERC Form 1 Page 323.189b
15	\$0					FERC Form 1 Page 323.191b
16	\$26,264,091	99.8099% (a)	\$26,214,163	51.2370%	\$13,431,351	
17	(\$135,569)	99.2997% (c)	(\$134,620)	51.2370%	(\$68,975)	Line 13
18	\$2,605,606	99.2997% (c)	\$2,587,359	51.2370%	\$1,325,685	Attachment 5 Line 6
19	\$0		\$0	51.2370%	\$0	Line 15
20	\$0		\$0	51.2370%	\$0	FERC Form 1 Page 350.18c
21	\$28,734,128		\$28,666,902		\$14,688,061	
<u>Payroll Tax Expense</u>						
22	\$2,271,348	99.8099% (a)	\$2,267,030	51.2370%	\$1,161,558	FERC Form 1 Page 263.3,4i - Footnote (d)
(d) <u>Payroll taxes FERC Form 1, page 263.i</u>						
	\$9,327		Massachusetts	\$23,571,202		
FICA	\$2,262,021		New Hampshire	\$2,662,307		
Payroll Taxes	\$0		Vermont	\$786,615		
State Unemployment	\$0		Maine	\$0		
Total	\$2,271,348		Rhode Island	\$151,330		
			Connecticut	\$0		
				\$27,171,454		
(e) <u>Property Taxes FF1, Page 263i</u>						

(a) Worksheet 7, Line 11

(b) Worksheet 7 Line 3

(c) Worksheet 7 Line 16

(d) Transmission Only - Payroll Taxes - Specifically identified in FERC Form 1

(e) Transmission Only - Property Taxes - Specifically Identified in FERC Form 1

(f) Transmission Only - Amortization of ITC - Specifically Identified in FERC Form 1

** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments.

Shading denotes an input

Line
No.

Source
Reference

PTF Transmission Plant Allocation Factor

NEP

1	PTF Transmission Investment	\$816,526,816
2	Total Transmission Investment	\$1,593,625,753
3	Percent Allocation (Line 1/Line 2)	51.2370%

Attachment 1, Page 1
FERC Form 1 Page 207.58g - Page 200.4b

Transmission Wages and Salaries Allocation Factor

4	Direct Transmission Wages and Salaries	\$0
5	Affiliated Company Transmission Wages and Salaries	\$23,467,616
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	\$23,467,616
7	Total Wages and Salaries	\$0
8	Administrative and General Wages and Salaries	\$0
9	Affiliated Company Wages and Salaries less A&G	\$23,512,307
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	\$23,512,307
11	Percent Allocation (Line 6/Line 10)	99.8099%

FERC Form 1 Page 354.14b
General Ledger Query

FERC Form 1 Page 354.28b
FERC Form 1 Page 354.27b
General Ledger Query

Plant Allocation Factor

12	Total Transmission Investment	\$1,593,625,753
13	plus Transmission-Related General Plant (Line 2 of Wkst. 3)	\$6,384,326
14	= Revised Numerator (Line 12 + Line 13)	\$1,600,010,079
15	Total Plant in Service	\$1,611,293,575
16	Percent Allocation (Line 14 / Line 16)	99.2997%

Line 2
Worksheet 5, Line 3, Column 3

FERC Form 1 Page 207.104g - Page 200.4b

Post-2003 PTF Allocation Factor

17	Total Post-2003 PTF Investment	\$ 327,705,145
18	Total Transmission Investment	\$1,593,625,753
19	Percent Allocation (Line 17/Line 18) for Post-2003 to Total Tx	20.5635%
20	Total Invst in Tx Plant/Total Plant in Serv *	
21	Post-2003 PTF Tx Plant/Total Invst in Tx Plant	20.4195%

Attachment 1 Line 7
Line 2

Line 19 * Line 16

**New England Power Company
Post-96 RNs Revenue Requirements
For Test Year Ended 12/31/2011**

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	FERC Form 1 Reference	TOTAL	
			Revenues (a)	Expenses (b)
NSTAR	115 kV Millbury-Medway 201 Line	Pg 332 Line 2 Col (g)		\$0
	HQ Phase II - AC in MA	Pg 332 Line 5 Col (g)		\$0
	345 kV "stabilizer" 342 Line	Pg 332 Line 3 Col (g)		\$0
	345 kV Carver - Walpole 331 Line	Pg 332 Line 13 Col (g)		\$0
	Second Canal Line	Pg 332 Line 4 Col (g)		\$0
	Bell Rock Road	Page 330.5 Line 12	\$0	
	Boston-Edison [345 kV Sandy-Tewksbury 337 line-345kV Tewksbury-Woburn 338 Line]	Page 330 Line 4	\$0	
	Boston-Edison [115 kV Tewksbury - Woburn M139 line - 115kV Tewksbury-Woburn N140 Line]	Page 330 Line 3	\$0	
	Public Service Co. -Moore 115 kV Substation	Page 330.1 Line 5	\$0	
	Boston Edison -345 kV Golden Hills-Mystic 349 Line	Page 330 Line 2	\$0	
	Boston Edison -345 kV NH/MA border - Tewksbury 394 Line (Seabrook)	Page 330.1 Line 8	\$0	
	345 kV Medway - Bridgewater 344 Line	Pg 330.5, Line 11	\$0	
EUA				
NEP	Chester SVC	Transmission Billing		\$0
	HQ Phase II - AC in MA	Page 330 Line 11	\$0	
	MWRA Transmission (MDC)	Contract - Line Lease/Use		\$0
VT Elec Co.	Comerford 115 kV Substation	Page 330.1 Line 12	\$0	
Totals			\$0	\$0

New England Power Company
2011 Informational Filing
PTF Plant Allocation

				<u>Percent Pre/Post</u>
1	2010	Pre-1997 PTF Transmission Plant	\$351,352,992	
2	2010	Post-1996 PTF Transmission Plant	\$725,670,117	
3	2011	Additions/Retirements	\$89,719,314	
4	2011	Pre-1997 PTF Transmission Plant	\$350,215,608	30.02%
5	2011	Post-1996 PTF Transmission Plant	\$816,526,816	69.98%
6	2011	Total PTF Transmission Plant	\$1,166,742,423	100.00%
7	2011	Post-2003 PTF Transmission Plant	\$327,705,145	

Sources:

- 1 PTF Plant Reports for previous year
- 2 PTF Plant Reports for previous year
- 3 Line 6 - Line 1 + Line 2
- 4 PTF Plant Reports for current year
- 5 PTF Plant Reports for current year
- 6 Line 4 + 5
- 7 PTF Plant Report: Post 2003 RSP Projects

Shading denotes an input

GROSS PLANT ASSOC. WITH HVDC LEASES
2011

LINE <u>NO</u>		(HVDC) NHH/NEH <u>LEASE</u>
1	Gross Plant Value Comerford Station to Tewksbury Line	\$0
	Allocation	
2	Miles used by NHH (a)	0
3	Total miles at Comerford Station	0
4	Percentage of Total Gross Plant leased by NHH (a)	0%
5	Total Gross Plant leased by NHH (a)	\$0
6	Total Land from Sandy Pond to New Hampshire	\$0
7	HVDC lines occupy 35% of Right of Way	0%
8	Total Land leased by NEH (a)	\$0
9	Total NEP Gross Plant leased by HVDC to be excluded from PTF Revenue requirement	\$0

Source:

- 1 FERC Form 1, Page 423.1, Lines 5 + 16
- 2 Total miles used per lease agreement
- 3 Total miles per lease agreement
- 4 Line 2 / Line 3
- 5 Line 1 * Line 4
- 6 FERC Form 1, Page 422-423, Line 15
- 7 Percentage per lease agreement
- 8 Line 6 * Line 7
- 9 Line 5 + Line 8

Note:

- (a) NEH and NHH are acronyms for two of the three "Hydro Companies, New England Hydro Transmission (NEH) Electric Company, New England Electric Transmission Corporation, and New England Hydro Transmission Electric Company, Inc. (NHH)" which own and lease the HVDC interconnection facilities to the participants to the NEPOOL HVDC agreements.

New England Power Company
Determination of Book Depreciation on Equity AFUDC

2011

1	Total Current Year Book Depreciation on Equity AFUDC	\$1,138,245
2	Less: Specifically identified Transmission-Related	
	Tewksbury Line	\$54,708
	Hydro-Quebec	\$23,543
	Montaup Transmission Only 1990 - 1999	\$9,713
	1998 Transmission	\$13,959
	1999 Transmission	\$42,457
	2000 Transmission	(\$8,299)
	2001 Transmission	\$23,561
	2002 Transmission	\$8,889
	2003 Transmission	\$16,500
	2004 Transmission	\$15,518
	2005 Transmission	\$49,757
	2006 Transmission	\$64,352
	2007 Transmission	\$42,418
	2008 Transmission	\$57,508
	2009 Transmission	\$98,437
	2010 Transmission	\$79,948
	2011 Transmission	\$157,814
		\$750,783
3	Total unidentified Book Depreciation on Equity AFUDC	\$387,462
4	Plant Allocator Factor	99.2997%
5	Allocated Transmission Related Book Depreciation on Equity AFUDC	\$384,749
6	Plus: Specifically Identified Transmission-Related Equity AFUDC	\$750,783
7	Total Transmission-Related Equity AFUDC	\$1,135,532
8	Post-96 PTF Allocation Factor	51.2370%
9	Transmission-Related Equity AFUDC	\$581,812

Sources:

- 1 & 2 Transmission Rates includes \$9,713 from Montaup
- 3 Line 1 - Line 2
- 4 Worksheet 5 - PTF Plant Allocation Factor
- 5 Line 3 * Line 4
- 6 Line 2
- 7 Line 5 + Line 6
- 8 Worksheet 6 - Post-96 PTF Allocation Factor
- 9 Line 7 * Line 8

New England Power Company
Determination of the PTF Related Integrated Facilities Charges

	<u>Narragansett</u> <u>2011</u>	<u>MECO</u> <u>2011</u>
1 Total Integrated Facilities Charges	\$0	\$0
2 Total 2011 PTF Property	\$0	\$0
3 Total Transmission Plant in 2011	\$0	\$0
4 NECO or MECO PTF Plant Allocator	0.00%	0.00%
5 PTF Related Integrated Facilities Charge	\$0	\$0
6 Total Integrated Facilities		<u><u>\$0</u></u>

Source:

- 1 FF1 Page 330.4 Lines 13 & 14 Col (n)
- 2 PowerPlant Reports
- 3 FF1 Page 207 Line 58 (g)
- 4 Line 2 / Line 3
- 5 Line 1 * Line 4
- 6 Line 5 Totals for Narragansett and Massachusetts Electric

Shading denotes an input

Attachment 5

New England Power Company
Development of 2011 Regulatory Commission Expense

Line No.		<u>2011</u>	<u>Source</u>
1	Total Regulatory Commission Expense - NEP	\$4,168,438	FERC Form1 Page 350.46d
2	Less: New Hampshire PUC Assessment	\$78,276	FERC Form1 Page 350.2d
3	Less: Mass Emergency Fund	\$0	FERC Form1 Page 350.7d
4	Less Mass DPU Special Assessment	\$229,133	FERC Form1 Page 350.8d
5	Less: Utility Expenses	\$1,255,423	FERC Form1 Page 350.46c
6	Total Federal Assessments	\$2,605,606	Line 1 - (Line 2-5)

Transmission Rents Received from Electric Property
New England Power Company

	<u>2011</u>
Revenues	\$1,213,781
Plant Allocation Factor	100.00%
Transmission Allocated	\$1,213,781
PTF Allocation	51.2370%
Total PTF Revenue	\$621,905

Source: Peoplesoft Activities #454002, 454020 and 454024 - see Analysis for details

Revenue for Short-Term Transmission Service under the NEPOOL Tariff
New England Power Company

	<u>2011</u>
Revenues	\$809,392
Post-96 PTF Percent	69.9835%
Total Post-96 PTF Revenue	\$566,441

Source: Short Term Through and Out Revenues from ISO New England

RTO-NE Regional Transmission Service
NHT's PTF Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO-NE Open Access Transmission Tariff
ROE BASED ON REHEARING ORDER BASE ROE SET AT 10.4% + 0.74 Bond Yield Adjustment + 0.5 RTO Adder
For Forecast RNS Rates Effective June 1, 2012 through May 31, 2013

Revenue Requirements for Test Year: 2011

Customer: NHT

Customer's NABs Number: _____

Name of Participant responsible for customer's billing: NHT

DUNS number of Participant responsible for customer's billing: _____

	<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>
Line No.		
Total of Attachment F - Sections A through I	1 <u>2,911,173</u> Pre-97 WS1, ln 14-22	<u>6,795,316</u> Post-96 WS1, ln 14-2
Total of Attachment F - Section J - Support Revenue	2 <u>0</u> Pre-97 WS1, ln 23	<u>0</u> Post-96 WS1, ln 23
Total of Attachment F - Section K - Support Expense	3 <u>726,518</u> Pre-97 WS1, ln 24	<u>0</u> Post-96 WS1, ln 24
Total of Attachment F - Section (L through O)	4 <u>(464)</u> Pre-97 WS1, ln 27	<u>(954)</u> Post-96 WS1, ln 27
Sub Total - Sum (A through I) - J + K + (L through O)	5 <u>3,637,227</u> Sum of above	<u>6,794,362</u> Sum of above
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	6 <u>N/A</u>	<u>\$1,113,975</u> Post-96 WS8, ln. 3
Annual True-up (per Attachment C to Attachment F Implementation Rule)	7 <u>\$ (407,158)</u> TU WS4, line 16	<u>\$ (959,812)</u> TU WS4, line 16
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)	8 <u>\$ 3,230,069</u> lns. 5+6+7	<u>\$6,948,525</u> lns. 5+6+7

Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements & Post-96 Revenue Requirements Subtotals, Forecasted Revenue Requirements, and True-ups (including interest)

\$10,178,594 Sum of lines 8 Pre-97 & Post-96 above

RTO-NE Regional Transmission Service
NHT's PTF Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO-NE Open Access Transmission Tariff
ROE BASED ON REHEARING ORDER BASE ROE SET AT 10.4% + 0.74 Bond Yield Adjustment + 0.5 RTO Adder
Pre-'97 ATRR

Shading denotes an input

Line No.		Attachment F	Pre-'97	Reference
		Reference		
	I. INVESTMENT BASE	Section:		
1	Transmission Plant	(A)(1)(a)	17,820,422	Pre-97 WS3, line 1 column 5
2	General Plant	(A)(1)(b)	0	Pre-97 WS3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	0	Pre-97 WS3, line 4 column 5
4	Total Plant (Lines 1+2+3)		17,820,422	
5	Accumulated Depreciation	(A)(1)(d)	6,282,153	Pre-97 WS3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	3,087,376	Pre-97 WS3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	0	Pre-97 WS3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	0	Pre-97 WS3, line 15 column 5
9	Net Investment (Line 4-5-6+7+8)		8,450,893	
10	Prepayments	(A)(1)(h)	0	Pre-97 WS3, line 16 column 5
11	Materials & Supplies	(A)(1)(i)	0	Pre-97 WS3, line 17 column 5
12	Cash Working Capital	(A)(1)(j)	195,144	Pre-97 WS3, line 24 column 5
13	Total Investment Base (Line 9+10+11+12)		8,646,037	
	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	1,153,037	Pre-97 WS2
15	Depreciation Expense	(B)	581,223	Pre-97 WS4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	0	Pre-97 WS4, line 4 column 5
17	Investment Tax Credit	(D)	0	Pre-97 WS4, line 5 column 5
18	Property Tax Expense	(E)	342,281	Pre-97 WS4, line 9 column 5
19	Payroll Tax Expense	(F)	0	Pre-97 WS4, line 33 column 5
20	Operation & Maintenance Expense	(G)	562,354	Pre-97 WS4, line 14 column 5
21	Administrative & General Expense	(H)	272,278	Pre-97 WS4, line 30 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0	NA
23	Transmission Support Revenue	(J)	0	NA
24	Transmission Support Expense	(K)	726,518	Pre-97 WS7
25	Transmission Related Expense from Generators	(L)	0	NA
26	Transmission Related Taxes and Fees Charge	(M)	0	NA
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(464)	Pre-97 WS8, line 5 column b
28	Transmission Rents Received from Electric Property	(O)	0	NA
29	Total Pre-'97 Revenue Requirements (Line 14 thru 28)		3,637,227	

NOTES:

1. All amounts represent NHT's 88.22889% ownership share in the Seabrook Transmission Substation.

RTO-NE Regional Transmission Service
NHT's PTF Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO-NE Open Access Transmission Tariff
ROE BASED ON REHEARING ORDER BASE ROE SET AT 10.4% + 0.74 Bond Yield Adjustment + 0.5 RTO Adder
Pre-'97 ATRR

Shading denotes an input

	CAPITALIZATION 12/31/11	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 16,080,443	40.02%	3.99%	1.60%	
PREFERRED STOCK	0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	24,101,363	59.98%	11.64%	6.98%	6.98%
TOTAL INVESTMENT RETURN	\$ 40,181,806	100.00%		8.58%	6.98%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0858

(b) Federal Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp}}{\text{PTF Inv. Base}} \right) / \text{Federal Income Tax Rate}}{1} \right) \times \text{Federal Income Tax Rate}$$

=
$$\left(\frac{0.0698 + \left(\frac{0 + 0}{8,646,037} \right) / 0.35}{1} \right) \times 0.35$$

= 0.0375846

(c) State Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp}}{\text{PTF Inv. Base}} \right) / \text{Federal Income Tax Rate}}{1} \right) + \text{State Income Tax Rate}$$

=
$$\left(\frac{0.0698 + \left(\frac{0 + 0}{8,646,037} \right) / 0.0375846}{1} \right) + 0.085$$

= 0.0099756

(a)+(b)+(c) Cost of Capital Rate = 0.1333602

	<u>(PTF)</u>	
INVESTMENT BASE	\$ 8,646,037	From Pre-97 WS1, line 13
x Cost of Capital Rate	0.1333602	
= Investment Return and Income Taxes	<u>1,153,037</u>	To Pre-97 WS1, Line 14

RTO-NE Regional Transmission Service
NHT's PTF Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO-NE Open Access Transmission Tariff
ROE BASED ON REHEARING ORDER BASE ROE SET AT 10.4% + 0.74 Bond Yield Adjustment + 0.5 RTO Adder
Pre-'97 ATRR

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) Pre-Post PTF Allocation Factor	(5) = (3)*(4) PTF Allocated	Reference for col (1)
<u>Transmission Plant</u>						
1 Transmission Plant (Pre-'97 PTF)	17,820,422	Directly Assigned	17,820,422	Directly Assigned	17,820,422	Pre-97 WS 5, line 1
2 General Plant	0		0		0	
3 Total (line 1+2)					<u>17,820,422</u>	
4 <u>Transmission Plant Held for Future Use</u>	0		0		<u>0</u>	
<u>Transmission Accumulated Depreciation</u>						
5 Transmission Accum. Depreciation	6,282,153	Directly Assigned	6,282,153	Directly Assigned	6,282,153	From Plant Data Support 5
6 General Plant Accum. Depreciation	0		0		0	
7 Total (line 5+6)					<u>6,282,153</u>	
<u>Transmission Accumulated Deferred Taxes</u>						
8 Accumulated Deferred Taxes (281-283)	3,087,376	Directly Assigned	3,087,376	Directly Assigned	3,087,376	From Plant Data Support 5
9 Accumulated Deferred Taxes (190)	0		0		0	
10 Total (line 8+9)					<u>3,087,376</u>	
11 <u>Transmission loss on Reacquired Debt</u>	0		0		<u>0</u>	
<u>Other Regulatory Assets</u>						
12 FAS 106	0		0		0	
13 FAS 109	0		0		0	
14 Other Regulatory Liabilities (254)	0		0		0	
15 Total (line 12+13+14)					<u>0</u>	
16 <u>Transmission Prepayments (165)</u>	0		0		<u>0</u>	
17 <u>Transmission Materials and Supplies (154)</u>	0		0		<u>0</u>	
<u>Cash Working Capital</u>						
19 Operation & Maintenance Expense					562,354	Pre-97 WS 1, Line 20
20 Administrative & General Expense					272,278	Pre-97 WS 1, Line 21
21 Transmission Support Expense					726,518	Pre-97 WS 7
22 Subtotal (line 19+20+21)					1,561,150	
23					<u>0.125</u>	x 45 / 360
24 Total (line 22 * line 23)					<u>195,144</u>	

Notes:

References:

(a) Worksheet 5, line 3 (Pre-97 PTF/HTF Transmission Plant Allocation Factor)

RTO-NE Regional Transmission Service
NHT's PTF Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO-NE Open Access Transmission Tariff
ROE BASED ON REHEARING ORDER BASE ROE SET AT 10.4% + 0.74 Bond Yield Adjustment + 0.5 RTO Adder
Pre-'97 ATRR

Shading denotes an input

Shading denotes an input							
Line No.		(1) Total	(2) Wage / PTF- Non-PTF Plant Allocation	(3) = (1)*(2) Transmission Allocated	(4) PTF/HTF Allocation Factor	(5) = (3)*(4) PTF Allocated	Reference for col (1)
	<u>Depreciation Expense</u>						
1	Transmission Depreciation - Pre-'97 PTF	581,223	Directly Assigned	581,223	Directly Assigned	581,223	Plant Data Su
2	General Depreciation	0		0		0	
3	Total (line 1+2)					<u>581,223</u>	
4	<u>Amortization of Loss on Reacquired Debt</u>	0		0		<u>0</u>	
5	<u>Amortization of Investment Tax Credits</u>	0		0		<u>0</u>	
	<u>Property Taxes</u>						
7	Transmission Property Taxes	1,145,452	100% (c)	1,145,452	29.8817% (a)	342,281	From Form 1
8	General Property Taxes	0		0		0	
9	Total (line 7+8)	1,145,452				<u>342,281</u>	
	<u>Transmission Operation and Maintenance</u>						
10	Operation and Maintenance (Directly Assigned to Transmission; Allocated to PTF)	1,881,936	Directly Assigned	1,881,936	29.8817% (a)	562,354	From Form 1
11	Transmission of Electricity by Others (#565)	0		0		0	
12	Load Dispatching (#561)	0		0		0	
13	Station Expenses & Rents (#562 / #567)	0		0		0	
14	Total lines: 10, 11, 12 & 13	1,881,936				<u>562,354</u>	
	<u>Transmission Administrative and General</u>						
20	Administrative and General	911,186					From Form 1
21	less Property Insurance (#924)	39,930					From Form 1
22	less Regulatory Commission Expenses (#928)	29,833					From Form 1
23	less General Advertising Expense (#930.1)	0					
24	Subtotal [line 20 minus (21 thru 23)]	841,423	Directly Assign ⁿ (b)	841,423	29.8817% (a)	251,431	
26	PLUS Property Insurance	39,930	100% (c)	39,930	29.8817% (a)	11,932	From Form 1
28	PLUS Regulatory Comm. Exp.: FERC Assessments	29,833	100% (c)	29,833	29.8817% (a)	8,915	From Form 1
29	PLUS Trans. Related General Advertising Expense	0		0		0	
30	Total A&G [line 20 plus (26 thru 29)]	<u>911,186</u>				<u>272,278</u>	
33	Payroll Tax Expense - Transmission Related Total	0	Directly Assign ⁿ (b)	0	29.8817% (a)	0	From Form 1

References:

- (a) Worksheet 5, line 3 (PTF/HTF Allocation Factor applicable to NHT)
- (b) Worksheet 5, line 14 (Wage and Salary Allocation Factor applicable to NHT. All Wages and Salaries are Transmission Related thus costs are directly assigned.)
- (c) Worksheet 5, line 19 (Transmission Plant Allocation Factor applicable to NHT. All plant owned by NHT is Transmission Related and thus costs are directly assigned.)

RTO-NE Regional Transmission Service
NHT's PTF Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO-NE Open Access Transmission Tariff
ROE BASED ON REHEARING ORDER BASE ROE SET AT 10.4% + 0.74 Bond Yield Adjustment + 0.5 RTO Add
Pre-'97 ATRR

Shading denotes an input

Line No.		Pre-'97	Reference
	<u>PTF/HTF Transmission Plant Allocation Factor</u>		
1	PTF Transmission Investment (Pre 1997)	17,820,422	Plant Data Support or Form 1
2	Total Transmission Investment	59,636,610	Plant Data Support or Form 1
3	Percent Allocation (Line 1/Line 2)	29.8817%	Line 1 / line 2
	<u>PTF/HTF Transmission Plant Allocation Factor</u>		
4	PTF Transmission Investment (Post-1996)	36,600,375	Plant Data Support or Form 1
5	Total Transmission Investment	59,636,610	Plant Data Support or Form 1
6	Percent Allocation (Line 4/Line 5)	61.3723%	Line 4 / line 5
	<u>Transmission Wages and Salaries Allocation Factor</u>		
7	Direct Transmission Wages and Salaries	0	Form 1
8	Affiliated Company Transmission Wages and Salaries	0	Form 1
9	Total Transmission Wages and Salaries (Line 7 + Line 8)	0	Sum Lines 7 + 8
10	Total Wages and Salaries	0	Form 1
11	Administrative and General Wages and Salaries	31,651	Form 1
12	Affiliated Company Wages and Salaries less A&G	0	
13	Total Wages and Salaries net of A&G (Line 10 - 11 + 12)	31,651	Sum Lines 10 + 11 + 12
14	Percent Allocation (Line 9/Line 13)	0.0000%	Line 9 / Line 13
	Force to	100%	because NHT has no other business function other than Tr
	<u>Plant Allocation Factor</u>		
15	Total Transmission Investment	59,636,610	Form 1
16	plus Transmission-Related General Plant (Line 2 of Wkst. 3)	0	Pre-97 WS3, Line 2
17	Total Transmission Related Investment (Line 15 + Line 16)	59,636,610	Sum Lines 15 + 16
18	Total Plant in Service	59,636,610	Form 1
19	Percent Allocation (Line 17 / Line 18)	100.0000%	Line 17 / Line 18
	<u>Pre-1997 and Post 1996 Transmission Plant</u>		
20	PTF PRE 1997 Transmission Investment	17,820,422	Plant Data Support or Form 1
21	PTF POST 1996 Transmission Investment	36,600,375	Plant Data Support or Form 1
22	Total PTF Transmission Plant (Line 20+21)	54,420,797	Sum Lines 20 + 21
23	Percentage PTF PRE 1997 Transmission Investment (Line 20 / 22)	32.7456%	Line 20 / Line 22
24	Percentage PTF POST 1996 Transmission Investment (Line 21 / 22)	67.2544%	Line 21 / Line 22
25	Total PTF Transmission Plant Percentage (Line 23 + 24)	100.0000%	Sum Lines 23 + 24

Notes

RTO-NE Regional Transmission Service
NHT's PTF Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO-NE Open Access Transmission Tariff
ROE BASED ON REHEARING ORDER BASE ROE SET AT 10.4% + 0.74 Bond Yield Adjustment + 0.5 RTO Adder
Pre-'97 ATRR

Affiliated Company Wages and Salaries



Shading denotes an input

Line		NHT
	"Affiliated" Transmission Wages and Salaries	
	#560 - 573	
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11	Total Transmission (1 thru 10)	0
12	Total "Affiliated" Wages and Salaries	0
	Less "Affiliated" Administrative and General Salaries	
	#920 - 935	
13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
21	Total Affiliated Administrative and General Salaries (13 thru 20)	0
22 = 12	Total "Affiliated" less A&G	0

Input Revenues associated with the NPTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Amount by which Support Expense exceeds Support Revenues	726,518
(To Worksheet 3, Line 21, Column 5)	

Page 8 of 34
Pre-97 Worksheet 7

RTO-NE Regional Transmission Service
NHT's PTF Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO-NE Open Access Transmission Tariff
ROE BASED ON REHEARING ORDER BASE ROE SET AT 10.4% + 0.74 Bond Yield Adjustment + 0.5 RTO Adder
Pre-'97 ATRR

Short-Term Revenues Received Under ISO-NE Tariff

Line No.	Revenue Source ^(a)	Total Amount ^(b)	Reference
1	TOUT Revenues	\$1,418	ISO-NE
2	Post-96 PTF Plant Allocator	67.3%	Post-96 WS5, line 24
3	Pre-97 PTF Plant Allocator	32.7%	Post-96 WS5, line 23
4	Post-96 Revenues	\$954	Line 1 x Line 2
5	Pre-97 Revenues	\$464	Line 1 x Line 3

RTO-NE Regional Transmission Service
NHT's PTF Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO-NE Open Access Transmission Tariff
ROE BASED ON REHEARING ORDER BASE ROE SET AT 10.4% + 0.74 Bond Yield Adjustment + 0.5 RTO Adder
Post-'96

Shading denotes an input

		Attachment F		
Line No.	Reference	NHT	Reference	
I. INVESTMENT BASE				
	Section:			
1	Transmission Plant	(A)(1)(a)	36,600,375	Post-96 WS 3, line 1, column 5
2	General Plant	(A)(1)(b)	0	Post-96 WS 3, line 2, column 5
3	Plant Held For Future Use	(A)(1)(c)	0	Post-96 WS 3, line 5, column 5
4	Total Plant (Lines 1+2+3)		36,600,375	
5	Accumulated Depreciation	(A)(1)(d)	2,835,728	Post-96 WS 3, line 8, column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	5,868,911	Post-96 WS 3, line 12, column 5
7	Loss On Reacquired Debt	(A)(1)(f)	0	Post-96 WS 3, line 14, column 5
8	Other Regulatory Assets	(A)(1)(g)	0	Post-96 WS 3, line 18, column 5
9	Net Investment (Line 4-5-6+7+8)		27,895,736	
10	Prepayments	(A)(1)(h)	42,861	Post-96 WS 3, line 19, column 5
11	Materials & Supplies	(A)(1)(i)	0	Post-96 WS 3, line 20, column 5
12	Cash Working Capital	(A)(1)(j)	214,275	Post-96 WS 3, line 27, column 5
13	Total Investment Base (Line 9+10+11+12)		28,152,872	
II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes (Post-'96 / Pre-'04 Investments)	(A)	3,754,473	Post-96 WS2
15	Incentive Investment Return and Income Taxes (Eligible Investments)	(A)	0	Post-96 WS2A
16	Depreciation Expense	(B)	623,649	Post-96 WS4, line 3 column 5
17	Amortization of Loss on Reacquired Debt	(C)	0	Post-96 WS4, line 4 column 5
18	Investment Tax Credit	(D)	0	Post-96 WS4, line 5 column 5
19	Property Tax Expense	(E)	702,990	Post-96 WS4, line 9 column 5
20	Payroll Tax Expense	(F)	0	Post-96 WS4, line 32 column 5
21	Operation & Maintenance Expense	(G)	1,154,987	Post-96 WS4, line 14 column 5
22	Administrative & General Expense	(H)	559,216	Post-96 WS4, line 28 column 5
23	Transmission Related Integrated Facilities Charge	(I)	0	NA
24	Transmission Support Revenue	(J)	0	Post-96 WS7
25	Transmission Support Expense	(K)	0	Post-96 WS7
26	Transmission Related Expense from Generators	(L)	0	NA
27	Transmission Related Taxes and Fees Charge	(M)	0	NA
28	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(954)	Post-96 WS9, line 7 column b
29	Transmission Rents Received from Electric Property	(O)	0	NA
30				
31	Total Post-96 Revenue Requirements (Line 14 thru 29)		6,794,362	

NOTES:

1. All amounts represent NHT's 88.22889% ownership share in the Seabrook Transmission Substation.

RTO-NE Regional Transmission Service
NHT's PTF Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO-NE Open Access Transmission Tariff
ROE BASED ON REHEARING ORDER BASE ROE SET AT 10.4% + 0.74 Bond Yield Adjustment + 0.5 RTO Adder
Post-'96

Shading denotes an input

	CAPITALIZATION 12/31/11	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 16,080,443	40.02%	3.99%	1.60%	
PREFERRED STOCK	-	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY (see note)	24,101,363	59.98%	11.64%	6.98%	6.98%
TOTAL INVESTMENT RETURN	\$ 40,181,806	100.00%		8.58%	6.98%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0858

(b) Federal Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit} + \frac{\text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right)}{1} \right) \times \text{Federal Income Tax Rate}}{\left(\frac{0.0698}{1} + \left(\frac{0}{2,030,118} \right) \right) \times 0.35}$$

= 0.0375846

(c) State Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit} + \frac{\text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right)}{1} \right) + \text{Federal Income Tax}}{\left(\frac{0.0698}{1} + \left(\frac{0}{2,030,118} \right) \right) + 0.0375846} \times \text{State Income Tax Rate}$$

= 0.0099756

(a)+(b)+(c) Cost of Capital Rate = 0.1333602

(PTF)

INVESTMENT BASE \$ 28,152,872 From Post-96 WS 1, line 13

x Cost of Capital Rate 0.1333602

= Investment Return and Income Taxes 3,754,473 To Post-96 WS 1, Line 14

Note: For purposes of deriving the equity component of NHT's cost of capital, NHT has recorded here as Common Equity, amounts booked as Advances from Associated Companies reflecting equity contributions made to NHT by NextEra Energy Capital Holdings, Inc, an affiliated company. See page 256 of NHT's 2011 Form 1.

RTO-NE Regional Transmission Service
NHT's PTF Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO-NE Open Access Transmission Tariff
ROE BASED ON REHEARING ORDER BASE ROE SET AT 10.4% + 0.74 Bond Yield Adjustment + 0.5 RTO Adder
Post-96

Shading denotes an input

Line No.		(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor	(5) = (3)/(4) PTF Allocated	Reference for col (1)
1	<u>Transmission Plant</u>						
2	Transmission Plant (Post-96 PTF)	36,600,375	Directly Assigned	36,600,375	Directly Assigned	36,600,375	Post-96 WS 5, line 4
3	General Plant	0				0	
3	Total (line 1+2)					36,600,375	
4	Transmission Plant (Post-'03 PTF incl. in line 1)	NA	Directly Assigned	NA	Directly Assigned	NA	Post-96 WS 5, line 26
5	<u>Transmission Plant Held for Future Use</u>	0		0		0	
6	<u>Transmission Accumulated Depreciation</u>						
7	Transmission Accum. Depreciation (note 1)	2,835,728	Directly Assigned	2,835,728	Directly Assigned	2,835,728	From Plant Data Support 5
8	General Plant Accum. Depreciation	0		0		0	
8	Total (line 6+7)					2,835,728	
9	Transmission Accum. Depreciation Post-2003 Investments (note 2)	NA	0	NA	0	NA	
10	<u>Transmission Accumulated Deferred Taxes</u>						
11	Accumulated Deferred Taxes (261-263) (FPL-NED Direct Assignment)	5,868,911	Directly Assigned	5,868,911	Directly Assigned	5,868,911	From Plant Data Support 5
12	Accumulated Deferred Taxes (190)	0		0		0	
12	Total (line 10+11)					5,868,911	
13	Accumulated Deferred Taxes Post-2003 Investments (note 2)	NA	NA	NA	NA	(b) NA	Note 2
14	<u>Transmission loss on Reacquired Debt</u>	0		0		0	
15	<u>Other Regulatory Assets</u>						
16	FAS 109	0		0		0	
17	FAS 109	0		0		0	
18	Other Regulatory Liabilities (254)	0		0		0	
18	Total (line 15+16+17)					0	
19	<u>Transmission Prepayments (165)</u>	69,838	100%	69,838	61.3723%	42,861	From Form 1 Data worksheet
20	<u>Transmission Materials and Supplies (154)</u>	0		0		0	
21	<u>Cash Working Capital</u>						
22	Operation & Maintenance Expense					1,154,987	Post-96 WS 1, Line 21
23	Administrative & General Expense					559,216	Post-96 WS 1, Line 22
24	Transmission Support Expense					0	Post-96 WS 7
25	Subtotal (line 22+23+24)					1,714,204	
26						0.125	x 45 / 360
27	Total (line 25 + line 26)					214,275	

Notes/ References:

RTO-NE Regional Transmission Service
NHT's PTF Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO-NE Open Access Transmission Tariff
ROE BASED ON REHEARING ORDER BASE ROE SET AT 10.4% + 0.74 Bond Yield Adjustment + 0.5 RTO Adder
Post-'96

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF/HTF Allocation Factor	(5) = (3)*(4) PTF Allocated	Reference for col (1)
Depreciation Expense						
1	623,649	100%	623,649	Directly Assigned	623,649	Plant Data Support 5 worksheet
2	0		0		0	
3					623,649	
4	0		0		0	
5	0		0		0	
Property Taxes						
7	1,145,452	100%	1,145,452	61.3723% (a)	702,990	From Form 1 Data worksheet
8	0		0		0	
9	1,145,452				702,990	
Transmission Operation and Maintenance						
10	1,881,936	Directly Assigned	1,881,936	61.3723% (a)	1,154,987	From Form 1 Data worksheet
11	0		0		0	
12	0		0		0	
13	0		0		0	
14	1,881,936				1,154,987	
Transmission Administrative and General						
15	911,186					From Form 1 Data worksheet
16	39,930					From Form 1 Data worksheet
17	29,833					From Form 1 Data worksheet
18	0					
19	841,423	Directly Assign(b)	841,423	61.3723% (a)	516,401	
25	39,930	100% (c)	39,930	61.3723% (a)	24,506	From Form 1 Data worksheet
26	29,833	100% (c)	29,833	61.3723% (a)	18,309	From Form 1 Data worksheet
27	0		0		0	
28	911,186		0	61.3723% (a)	559,216	
32	0	Directly Assign(b)	0	61.3723% (a)	0	From Form 1 Data worksheet

Notes:

Reference (a) Worksheet 5, line 3 (PTF/HTF Allocation Factor applicable to NHT)
(b) Worksheet 5, line 14 (Wage and Salary Allocation Factor applicable to NHT. All Wages and Salaries are Transmission Related thus costs are directly assigned.)
(c) Worksheet 5, line 19 (Transmission Plant Allocation Factor applicable to NHT. All plant owned by NHT is Transmission Related and thus costs are directly assigned.)

RTO-NE Regional Transmission Service
NHT's PTF Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO-NE Open Access Transmission Tariff
ROE BASED ON REHEARING ORDER BASE ROE SET AT 10.4% + 0.74 Bond Yield Adjustment + 0.5 RTO Adder
Post-'96

Shading denotes an input

Line No.		NHT	Reference
<u>PTF/HTF Transmission Plant Allocation Factor</u>			
1	PTF Transmission Investment (Pre 1997)	17,820,422	From Data Support 5 worksheet
2	Total Transmission Investment	59,636,610	From NHT 2011 Form 1 - See worksheet "Form 1 Data"
3	Percent Allocation	29.8817%	Line 1 / line 2
<u>PTF/HTF Transmission Plant Allocation Factor</u>			
4	PTF Transmission Investment (Post-1996)	36,600,375	From Data Support 1 & 4 worksheets
5	Total Transmission Investment	59,636,610	From NHT 2011 Form 1 - See worksheet "Form 1 Data"
6	Percent Allocation	61.3723%	Line 4 / line 5
<u>Transmission Wages and Salaries Allocation Factor</u>			
7	Direct Transmission Wages and Salaries	0	Form 1
8	Affiliated Company Transmission Wages and Salaries	0	Form 1
9	Total Transmission Wages and Salaries	0	Sum Lines 7 + 8
10	Total Wages and Salaries	0	Form 1
11	Administrative and General Wages and Salaries	31,651	Form 1
12	Affiliated Company Wages and Salaries less A&G	0	
13	Total Wages and Salaries net of A&G	31,651	Sum Lines 10 + 11 + 12
14	Percent Allocation	0.0000%	Line 9 / Line 13
	Force to	100%	because NHT has no other business function other than Transmission
<u>Plant Allocation Factor</u>			
15	Total Transmission Investment	59,636,610	Form 1
16	plus Transmission-Related General Plant	0	
17	Total Transmission Related Investment	59,636,610	Sum Lines 15 + 16
18	Total Plant in Service	59,636,610	Form 1
19	Percent Allocation	100.0000%	Line 17 / Line 18
<u>Pre-1997 and Post 1996 Transmission Plant</u>			
20	PTF PRE 1997 Transmission Investment	17,820,422	Plant Data Support or Form 1
21	PTF POST 1996 Transmission Investment	36,600,375	Plant Data Support or Form 1
22	Total PTF Transmission Plant	54,420,797	Sum Lines 20 + 21
23	Percentage PTF PRE 1997 Transmission Investment	32.7456%	Line 20 / Line 22
24	Percentage PTF POST 1996 Transmission Investment	67.2544%	Line 21 / Line 22
25	Total PTF Transmission Plant Percentage	100.0000%	Sum Lines 23 + 24
26	Post-2003 Transmission Investment	NA	
27	Total Transmission Investment	59,636,610	Form 1
28	Post-2003 PTF as Percentage of Total Transmission Investment	NA	Line 26 / Line 27
29	Post-2009 Transmission Investment Eligible for ROE Incentive	0	No 2003 RSP Projects
30	Total Transmission Investment	59,636,610	
31	Post-2009 PTF in RSP as Percentage of Total Transmission Investment	0	

Notes

- Total Plant In-Service reflects Total Plant In-Service adjusted to remove an amount reflecting a Capital Contribution to be paid by NHT's Local Customer as a Direct Assignment Facilities Charge associated with upgraded facilities not included for regional cost recovery under RNS Rates.
- Post-96 PTF Investment includes all such PTF investment plus amounts associated with NHT's Breaker Replacement/Reconfiguration Upgrade implemented pursuant to approved Proposed Plan Application (PLC-08-T01) for which a final cost recovery pursuant to ISO-NE Tariff Schedule 12C has yet to be determined. The amount included herein reflects NHT's requested amount for regional cost recovery and is subject to refund or surcharge pending final determination.

RTO-NE Regional Transmission Service
NHT's PTF Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO-NE Open Access Transmission Tariff
ROE BASED ON REHEARING ORDER BASE ROE SET AT 10.4% + 0.74 Bond Yield Adjustment + 0.5 RTO Adder
Post-'96
Affiliated Company Wages and Salaries

Shading denotes an input

Line		NHT
	"Affiliated" Transmission Wages and Salaries	
	#560 - 573	
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11	Total Transmission (1 thru 10)	0
12	Total "Affiliated" Wages and Salaries	0
	Less "Affiliated" Administrative and General Salaries	
	#920 - 935	
13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
21	Total Affiliated Administrative and General Salaries (13 thru 20)	0
22	Total "Affiliated" less A&G	0

RTO-NE Regional Transmission Service
NHT's PTF Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO-NE Open Access Transmission Tariff
ROE BASED ON REHEARING ORDER BASE ROE SET AT 10.4% + 0.74 Bond Yield Adjustment + 0.5 RTO Adder
Post-'96

Input Revenues associated with the NPTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Post-97 WS1, Lines 23 and 24.

Shading denotes an input			NHT	
Participant	PTF Supporting Facilities	FERC Form 1	Revenues (a)	Expenses (b)
				0
				0
Total =			0	0

Amount by which Support Expense exceeds Support Revenues
 (To Post-96 WS3, Line 24, Column 5) 0

Note: All amounts represent NHT's 88.22889% ownership share in the Seabrook Substation.

RTO-NE Regional Transmission Service
NHT's PTF Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO-NE Open Access Transmission Tariff
ROE BASED ON REHEARING ORDER BASE ROE SET AT 10.4% + 0.74 Bond Yield Adjustment + 0.5 RTO Adder

Forecast Transmission Revenue Requirements of PTF Facilities

Shading denotes an input

I. FORECASTED TRANSMISSION REVENUE REQUIREMENTS		Period	Attachment F Reference Section:	NHT	Reference
Line No.					
1	Forecasted Transmission Plant Additions	2011	Appendix C	\$6,000,000	Note 1
2	Carrying Charge Factor		Appendix C	18.57%	Line 15
3	Total Forecasted Revenue Requirements (Lines 1*2)			<u>\$1,113,975</u>	Line 1 x Line 2
II. CARRYING CHARGE FACTOR					
4	Investment Return and Income Taxes (Post-'96 / Pre-'04 Investments)		(A)	\$3,754,473	Post-96, WS 1, line 14
5	Incentive Investment Return and Income Taxes (Eligible Investments)			0	Post-96, WS 1, line 15
6	Depreciation Expense		(B)	623,649	Post-96, WS 1, line 16
7	Amortization of Loss on Reacquired Debt		(C)	0	Post-96, WS 1, line 17
8	Investment Tax Credit		(D)	0	Post-96, WS 1, line 18
9	Property Tax Expense		(E)	702,990	Post-96, WS 1, line 19
10	Payroll Tax Expense		(F)	0	Post-96, WS 1, line 20
11	Operation & Maintenance Expense		(G)	1,154,987	Post-96, WS 1, line 21
12	Administrative & General Expense		(H)	559,216	Post-96, WS 1, line 22
13	Total Expenses (Lines 4 thru 12)			<u>\$6,795,316</u>	Sum lines 4 thru 12
14	PTF Transmission Plant		(A)(1)(a)	<u>\$36,600,375</u>	Post-96, WS 1, line 4
15	Carrying Charge Factor (Lines 13/14)			<u>18.57%</u>	Line 13 / Line 15

Note:

Forecast Plant Addition includes following projects expected to be placed in service / closed to books by 12/31/12:

1 ROHE Monitoring System on GIS (Phase 1)	\$ 2,450,000
2 Thermography Monitor	795,000
3 Fiber Network	670,000
4 363 Line TTR-6 Switch Replacement	525,000
5 Protective Relay Upgrades and Remote Communication Processor	420,000
6 Remote Contamination Monitor (RTM) weather station	345,000
7 Facility Security	235,000
8 SF6 Maintenance Building Modifications	215,000
9 Switchyard Battery System Replacements	210,000
10 Capital Tools	<u>135,000</u>

Total Forecast Capital Additions 6,000,000

DONE

**NHT's PTF Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO-NE Open Access Transmission Tariff**

Short-Term Revenues Received Under ISO-NE Tariff

Line No.	(a) Revenue Source	(b) Total Amount	Reference
1	TOUT Revenues	\$1,418	ISO-NE
2	Post-96 PTF Plant Allocator	67.3%	Post-96 WS5, line 24
3	Pre-97 PTF Plant Allocator	32.7%	Post-96 WS5, line 23
4	Post-96 Revenues	\$954	Line 1 x Line 2
5	Pre-97 Revenues	\$464	Line 1 x Line 3

NHT
Annual Revenue Requirements of PTF Facilities
Supporting True Up for Rates Effective June 1, 2011

Shading denotes an input

I. INVESTMENT BASE		Attachment F Reference Section:	PRE97	POST 1996	Reference
Line No.					
1	Transmission Plant		\$ 17,820,422	\$ 36,600,375	Per-97 and Post-96 WS1
2	General Plant	Appendix C	0	0	Per-97 and Post-96 WS1
3	Plant Held For Future Use	Appendix C	0	0	Per-97 and Post-96 WS1
4	Total Plant (Lines 1+2+3)		\$ 17,820,422	\$ 36,600,375	Per-97 and Post-96 WS1
5	Accumulated Depreciation	Appendix C	\$ 6,282,153	\$ 2,835,728	Per-97 and Post-96 WS1
6	Accumulated Deferred Income Taxes	Appendix C	3,087,376	5,868,911	Per-97 and Post-96 WS1
7	Loss On Reacquired Debt	Appendix C	0	0	Per-97 and Post-96 WS1
8	Other Regulatory Assets	Appendix C	0	0	Per-97 and Post-96 WS1
9	Net Investment (Line 4-5-6+7+8)		\$ 8,450,893	\$ 27,895,736	Per-97 and Post-96 WS1
10	Prepayments	Appendix C	0	42,861	Per-97 and Post-96 WS1
11	Materials & Supplies	Appendix C	0	0	Per-97 and Post-96 WS1
12	Cash Working Capital	Appendix C	195,144	214,275	Per-97 and Post-96 WS1
13	Total Investment Base (Line 9+10+11+12)		\$ 8,646,037	\$ 28,152,872	Per-97 and Post-96 WS1
II. REVENUE REQUIREMENTS					
14	Investment Return and Income Taxes	Appendix C	\$ 1,153,037	\$ 3,754,473	Per-97 and Post-96 WS1
15	Incentive Return and Income Taxes (Post-2003 Investments)	Appendix C		0	Per-97 and Post-96 WS1
16	Depreciation Expense	Appendix C	581,223	623,649	Per-97 and Post-96 WS1
17	Amortization of Loss on Reacquired Debt	Appendix C	0	0	Per-97 and Post-96 WS1
18	Investment Tax Credit	Appendix C	0	0	Per-97 and Post-96 WS1
19	Property Tax Expense	Appendix C	342,281	702,990	Per-97 and Post-96 WS1
20	Payroll Tax Expense	Appendix C	0	0	Per-97 and Post-96 WS1
21	Operation & Maintenance Expense	Appendix C	562,354	1,154,987	Per-97 and Post-96 WS1
22	Administrative & General Expense	Appendix C	272,278	559,216	Per-97 and Post-96 WS1
23	Transmission Related Integrated Facilities Charge	Appendix C	0	0	Per-97 and Post-96 WS1
24	Transmission Support Revenue	Appendix C	0	0	Per-97 and Post-96 WS1
25	Transmission Support Expense	Appendix C	726,518	0	Per-97 and Post-96 WS1
26	Transmission Related Expense from Generators	Appendix C	0	0	Per-97 and Post-96 WS1
27	Transmission Related Taxes and Fees Charge	Appendix C	0	0	Per-97 and Post-96 WS1
28	Revenue for ST Trans. Service Under NEPOOL Tariff	Appendix C	(464)	(954)	Per-97 and Post-96 WS1
29	Transmission Rents Received from Electric Property	Appendix C	0	0	Per-97 and Post-96 WS1
30	Restated per 2011 Form 1 Total Revenue Requirements (Line 14 thru 28)		\$ 3,637,227	\$ 6,794,362	Per-97 and Post-96 WS1
31	As-Filed / Billed June 1, 2010 - May 31, 2011 less True-Up component		\$ 4,031,254	\$ 7,723,221	June 2, 2009 RNS Rates
32	True-Up (Over) / Under Collection (line 30-31)		\$ (394,027)	\$ (928,859)	line 30 less line 31

NHT
FERC Interest Calculation associated with Under / (Over)
Transmission Revenue Requirements of PTF Facilities

Undercollection / (Overcollection)						
PRE97	\$	(394,027)	Over collection			
Post1996	\$	(928,859)	Over collection			
Net Total	\$	(1,322,886)	Overcollection			
				FERC		
Line No.	Initial Billing Period	PRE97 Balance	POST 1996 Balance	Monthly Interest Rate	PRE97 Interest	POST 1996 Interest
1	June 2011	\$ (394,027.48)	\$ (928,859)	0.27%	\$ (1,063.87)	\$ (2,508)
2	July 2011	(395,091.36)	(931,366.91)	0.27%	(1,066.75)	(2,514.69)
3	August 2011	(395,091.36)	(931,366.91)	0.28%	(1,106.26)	(2,607.83)
4	September 2011	(395,091.36)	(931,366.91)	0.27%	(1,066.75)	(2,514.69)
6	October 2011	(398,331.10)	(939,004.12)	0.28%	(1,115.33)	(2,629.21)
7	November 2011	(398,331.10)	(939,004.12)	0.27%	(1,075.49)	(2,535.31)
8	December 2011	(398,331.10)	(939,004.12)	0.28%	(1,115.33)	(2,629.21)
9	January 2012	(401,637.25)	(946,797.85)	0.28%	(1,124.58)	(2,651.03)
10	February 2012	(401,637.25)	(946,797.85)	0.26%	(1,044.26)	(2,461.67)
11	March 2012	(401,637.25)	(946,797.85)	0.28%	(1,124.58)	(2,651.03)
12	April 2012	(404,930.68)	(954,561.59)	0.27%	(1,093.31)	(2,577.32)
13	May 2012	(404,930.68)	(954,561.59)	0.28%	(1,133.81)	(2,672.77)
14		Total Interest			\$ (13,130)	\$ (30,953)
15		True-Up			\$ (394,027)	\$ (928,859)
16		Total TU & Int			\$ (407,158)	\$ (959,812)
					\$ (1,366,969)	Over Collection Credit to PTF AT

CALCULATION OF PRE 1997 AND POST 1996
PLANT IN SERVICE AND ACCUMULATED DEPRECIATION

	<u>Pre - 97</u>	<u>Post - 96</u>										<u>Total Pre 97 and Post 96</u>
		<u>Pre -2004</u>	<u>2004 Additions</u>	<u>2005 Additions</u>	<u>2006 Additions</u>	<u>2007 Additions</u>	<u>2008 Additions</u>	<u>2009 Additions</u>	<u>2010 Additions</u>	<u>2011 Additions</u>	<u>Total Post - 96</u>	
Plant in Service at 12/31/03	21,996,233	2,009,542	-	-	-	-	-	-	-	-	2,009,542	24,005,775
Accumulated provision for Depreciation	6,436,069	587,989	-	-	-	-	-	-	-	-	587,989	7,024,058
	15,560,164	1,421,553	-	-	-	-	-	-	-	-	1,421,553	16,981,717
Monthly Depreciation Expense												
Depreciable Balance	21,996,233	2,009,542	31,762	-	-	-	-	-	-	-	2,041,304	24,037,537
Monthly Depreciation Rate = .0312 /12	0.0026	0.0026	0.0026	0.0026	-	-	-	-	-	-	-	-
Monthly Depreciation Expense	57,190.21	5,225	82.58	-	-	-	-	-	-	-	5,307	62,498
Jan - December 2004	12	12	11.5	-	-	-	-	-	-	-	-	-
2004 Depreciation Expense	686,282	62,698	950	-	-	-	-	-	-	-	63,647	749,930
Plant In Service at 12/31/04	21,996,233	2,009,542	31,762	-	-	-	-	-	-	-	2,041,304	24,037,537
Accumulated provision for Depreciation at 12/31/04	7,122,351	650,687	950	-	-	-	-	-	-	-	651,636	7,773,988
Net Plant NBV @ 12/31/04	14,873,882	1,358,855	30,813	-	-	-	-	-	-	-	1,389,668	16,263,550
<u>Additions</u>												
Jan - August				0	-	-	-	-	-	-	-	-
September				255,084	255,084	-	-	-	-	-	255,084	255,084
October				0	-	-	-	-	-	-	-	-
November				350,072	350,072	-	-	-	-	-	350,072	350,072
December				(704)	(704)	-	-	-	-	-	(704)	(704)
<u>Retirements and Removal</u>												
Jan - August	0			-	-	-	-	-	-	-	-	-
September	132,343			-	-	-	-	-	-	-	-	132,343
October	0			-	-	-	-	-	-	-	-	-
November	268,687			-	-	-	-	-	-	-	-	268,687
December	0			-	-	-	-	-	-	-	-	-
<u>Monthly Depreciation Expense</u>												
Depreciable Balance @ 12/31/04	21,996,233	2,009,542	31,762	-	-	-	-	-	-	-	2,041,304	24,037,537
Monthly Depreciation Rate = .0312 /12	0.0026	0.0026	0.0026	-	-	-	-	-	-	-	-	-
Monthly Depreciation Expense	57,190	5,225	83	-	-	-	-	-	-	-	5,307	62,498
Jan - December	12	12	12	-	-	-	-	-	-	-	-	-
<u>Depreciation Expense on 2004 Balance</u>	<u>686,282</u>	<u>62,698</u>	<u>991</u>								<u>63,689</u>	<u>749,971</u>
<u>Add:</u>												
September Additions/Retirements	(132,343)			255,084	-	-	-	-	-	-	-	-
Monthly Depreciation Rate = .0312 /12	0.0026			0.0026	-	-	-	-	-	-	-	-
Monthly Depreciation Expense	(344)			663	-	-	-	-	-	-	-	-
Sept - December	4			4	-	-	-	-	-	-	-	-
<u>Deprec Exp.on Sept Addition/Retirement</u>	<u>(1,376)</u>			<u>2,653</u>							<u>2,653</u>	<u>1,277</u>
November Additions/Retirements	(268,687)			350,072	-	-	-	-	-	-	-	-
Monthly Depreciation Rate = .0312 /12	0.0026			0.0026	-	-	-	-	-	-	-	-
Monthly Depreciation Expense	(699)			910	-	-	-	-	-	-	-	-
Nov - December	1.5			1.5	-	-	-	-	-	-	-	-
<u>Deprec Exp.on Nov Addition/Retirement</u>	<u>(1,048)</u>			<u>1,365</u>							<u>1,365</u>	<u>317</u>
December Additions/Retirements	0			(704)	-	-	-	-	-	-	-	-
Monthly Depreciation Rate = .0312 /12				0.0026	-	-	-	-	-	-	-	-
Monthly Depreciation Expense				(2)	-	-	-	-	-	-	-	-
December				0.5	-	-	-	-	-	-	-	-
<u>Deprec Exp.on Dec Addition/Retirement</u>				<u>(1)</u>							<u>(1)</u>	<u>(1)</u>
Plant In Service at 12/31/05	21,595,203	2,009,542	31,762	604,451	-	-	-	-	-	-	2,645,756	24,240,959
Accumulated provision for Depreciation at 12/31/05	7,405,180	713,384	1,941	4,017	-	-	-	-	-	-	719,342	8,124,522
Net Plant NBV @ 12/31/05	14,190,023	1,296,158	29,822	600,434	-	-	-	-	-	-	1,926,413	16,116,437

	Pre - 97	Post - 96										Total Pre 97 and Post 96
		Pre -2004	2004 Additions	2005 Additions	2006 Additions	2007 Additions	2008 Additions	2009 Additions	2010 Additions	2011 Additions	Total Post - 96	
Plant in Service at 12/31/03	21,996,233	2,009,542	-	-	-	-	-	-	-	-	2,009,542	24,005,775
	Pre - 97 (PTF)	Post - 96 (PTF)										Total Pre 97 and Post 96 (PTF)
		Pre -2004	2004 Additions	2005 Additions	2006 Additions						Total Post - 96	
Plant in Service at 12/31/05	21,595,203	2,009,542	31,762	604,451	-	-	-	-	-	-	2,645,756	24,240,959
Accumulated provision for Depreciation at 12/31/05	7,405,180	713,384	1,941	4,017	-	-	-	-	-	-	719,342	8,124,522
Net Plant NBV @ 12/31/05	<u>14,190,023</u>	<u>1,296,158</u>	<u>29,822</u>	<u>600,434</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>1,926,413</u>	<u>16,116,437</u>

2006												
Additions												
Jan				8,876								
March				60								
June				356,063								
August				18,807								
September				13,845								
October				(448)								
November				448								
December				977								
Retirements and Removal												
Jan - May												
June Retirement	134,088											
June - Removal	3,000											
July - Dec												
Monthly Depreciation Expense												
Depreciable Balance @ 12/31/05	21,595,203	2,009,542	31,762	604,451	-						2,645,756	24,240,959
Monthly Depreciation Rate = .0312 /12	0.0026	0.0026	0.0026	0.0026								
Monthly Depreciation Expense	56,148	5,225	83	1,572							6,879	
Jan - December	12	12	12	12								
Depreciation Expense on 2005 Balance	673,770	62,698	991	18,859							82,548	
Add:												
January Additions/Retirements				8,876								
Monthly Depreciation Rate = .0312 /12				0.0026								
Monthly Depreciation Expense				23								
Jan - December				11.5								
Deprec Exp.on Jan Addition/Retirement				265							265	
Add:												
March Additions/Retirements				60								
Monthly Depreciation Rate = .0312 /12				0.0026								
Monthly Depreciation Expense				0.16								
March - December				9.5								
Deprec Exp.on March Addition/Retirement				1							1	
Add:												
June Additions/Retirements	(134,088)			353,063								
Monthly Depreciation Rate = .0312 /12	0.0026			0.0026								
Monthly Depreciation Expense	(349)			917.96								
June - December	6.5			6.5								
Deprec Exp.on June Addition/Retirement	(2,266)			5,967							5,967	
Add:												
Aug Additions/Retirements				18,807								
Monthly Depreciation Rate = .0312 /12				0.0026								
Monthly Depreciation Expense				48.90								
Aug - December				4.5								
Deprec Exp.on August Addition/Retirement				220							220	
Add:												
Sept Additions/Retirements				13,845								
Monthly Depreciation Rate = .0312 /12				0.0026								
Monthly Depreciation Expense				36.00								
Sept - December				3.5								
Deprec Exp.on Sept Addition/Retirement				126							126	
Add:												
Oct Additions/Retirements				(448)								
Monthly Depreciation Rate = .0312 /12				0.0026								
Monthly Depreciation Expense				(1.16)								
Oct - December				2.5								
Deprec Exp.on June Addition/Retirement				(3)							(3)	
Add:												
Nov. Additions/Retirements				448								
Monthly Depreciation Rate = .0312 /12				0.0026								
Monthly Depreciation Expense				1.16								
Nov. - December				1.5								
Deprec Exp.on June Addition/Retirement				2							2	
Add:												
Dec Additions/Retirements				977								
Monthly Depreciation Rate = .0312 /12				0.0026								
Monthly Depreciation Expense				2.54								
December				0.5								
Deprec Exp.on Dec Addition/Retirement				1							1	
Plant In Service at 12/31/06	21,458,115	2,009,542	31,762	604,451	398,628						3,044,384	24,502,499
Accumulated provision for Depreciation at 12/31/06	7,939,596	776,082	2,932	22,876	6,580						808,470	8,748,066
Net Plant NBV @ 12/31/06	<u>13,518,519</u>	<u>1,233,460</u>	<u>28,831</u>	<u>581,575</u>	<u>392,048</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>2,235,914</u>	<u>15,754,433</u>

Depreciation expense 2006	671,504	89,127										760,632

YEAR 2007	Pre - 97 (PTF)	Post - 96 (PTF)										Total Pre 97 and Post 96 (PTF)
		Pre -2004	2004 Additions	2005 Additions	2006 Additions	2007 Additions						Total Post - 96

	Pre - 97	Post - 96										Total Pre 97 and Post 96
		Pre -2004	2004 Additions	2005 Additions	2006 Additions	2007 Additions	2008 Additions	2009 Additions	2010 Additions	2011 Additions	Total Post - 96	
Plant in Service at 12/31/03	21,996,233	2,009,542	-	-	-	-	-	-	-	-	2,009,542	24,005,775
Plant In Service at 12/31/06	21,458,115	2,009,542	31,762	604,451	398,628	-	-	-	-	-	3,044,384	24,502,499
Accumulated provision for Depreciation at 12/31/06	7,939,596	776,082	2,932	22,876	6,580	-	-	-	-	-	808,470	8,748,066
Net Plant NBV @ 12/31/06	13,518,519	1,233,460	28,831	581,575	392,048	-	-	-	-	-	2,235,914	15,754,433
2007												
Additions												
March						3,018						
April						(964)						
May						243,906						
June						53,452						
July						5,886						
September						131,867						
November						29,547						
December						2,878						
Retirements and Removal												
Jan - Apr												
May Retirement	134,088											
May - Removal	-											
June - Dec												
Monthly Depreciation Expense												
Depreciable Balance @ 12/31/06	21,458,115	2,009,542	31,762	604,451	398,628	-	-	-	-	-	3,044,384	24,502,499
Monthly Depreciation Rate = .0312 /12	0.0026	0.0026	0.0026	0.0026	0.0026	-	-	-	-	-	-	-
Monthly Depreciation Expense	55,791	5,225	83	1,572	1,036	-	-	-	-	-	-	7,915
Jan - December	12	12	12	12	12	-	-	-	-	-	-	-
Depreciation Expense on 2006 Balance Add:	669,493	62,698	991	18,859	12,437	-	-	-	-	-	-	94,985
March Additions/Retirements						3,018						
Monthly Depreciation Rate = .0312 /12						0.0026						
Monthly Depreciation Expense						8						
Mar - December						9.5						
Deprec Exp.on Mar Addition/Retirement						75						75
April Additions/Retirements						(964)						
Monthly Depreciation Rate = .0312 /12						0.0026						
Monthly Depreciation Expense						(2,511)						
April - December						8.5						
Deprec Exp.on April Addition/Retirement						(21)						(21)
May Additions/Retirements	(134,088)					243,906						
Monthly Depreciation Rate = .0312 /12	0.0026					0.0026						
Monthly Depreciation Expense	(349)					634.16						
May - December	7.5					7.5						
Deprec Exp.on May Addition/Retirement	(2,615)					4,756						4,756
June Additions/Retirements						53,452						
Monthly Depreciation Rate = .0312 /12						0.0026						
Monthly Depreciation Expense						138.98						
Jun - December						6.5						
Deprec Exp.on June Addition/Retirement						903						903
July Additions/Retirements						5,886						
Monthly Depreciation Rate = .0312 /12						0.0026						
Monthly Depreciation Expense						15.30						
July - December						5.5						
Deprec Exp.on July Addition/Retirement						84						84
Sept Additions/Retirements						131,867						
Monthly Depreciation Rate = .0312 /12						0.0026						
Monthly Depreciation Expense						342.85						
Sept - December						3.5						
Deprec Exp.on Sept Addition/Retirement						1,200						1,200
Nov. Additions/Retirements						29,547						
Monthly Depreciation Rate = .0312 /12						0.0026						
Monthly Depreciation Expense						76.82						
Nov. - December						1.5						
Deprec Exp.on Nov Addition/Retirement						115						115
Dec Additions/Retirements						2,878						
Monthly Depreciation Rate = .0312 /12						0.0026						
Monthly Depreciation Expense						7.48						
December						0.5						
Deprec Exp.on Dec Addition/Retirement						4						4
Plant In Service at 12/31/07	21,324,028	2,009,542	31,762	604,451	398,628	469,590	-	-	-	-	3,513,974	24,838,002
Accumulated provision for Depreciation at 12/31/07	8,472,387	838,780	3,923	41,735	19,017	7,116	-	-	-	-	910,570	9,382,958
Net Plant NBV @ 12/31/07	12,851,641	1,170,762	27,840	562,716	379,611	462,474	-	-	-	-	2,603,403	15,455,044

Depreciation expense 2007	666,878										102,101	768,979

YEAR 2008	Pre - 97 (PTF)	Post - 96 (PTF)										Total Pre 97 and Post 96 (PTF)
		Pre -2004	2004 Additions	2005 Additions	2006 Additions	2007 Additions	2008 Additions				Total Post - 96	

Plant In Service at 12/31/07	21,324,028	2,009,542	31,762	604,451	398,628	469,590	-	-	-	-	3,513,974	24,838,002

	Pre - 97	Post - 96										Total Pre 97 and Post 96
		Pre -2004	2004 Additions	2005 Additions	2006 Additions	2007 Additions	2008 Additions	2009 Additions	2010 Additions	2011 Additions	Total Post - 96	
Plant in Service at 12/31/03	21,996,233	2,009,542	-	-	-	-	-	-	-	-	2,009,542	24,005,775
Accumulated provision for Depreciation at 12/31/07	8,472,387	838,780	3,923	41,735	19,017	7,116	-	-	-	-	910,570	9,382,958
Net Plant NBV @ 12/31/07	12,851,641	1,170,762	27,840	562,716	379,611	462,474	-	-	-	-	2,603,403	15,455,044

2008												
Additions												
January							425					
February							1,168					
March							840					
April							2,419					
May							187					
June							16,922					
October							91,340					
December												
Retirements and Removal												
Jan - Mar												
April - June												
July - Sept												
Oct - Dec												
Monthly Depreciation Expense												
Depreciable Balance @ 12/31/07	21,324,028	2,009,542	31,762	604,451	398,628	469,590					3,513,974	24,838,002
Monthly Depreciation Rate = .0312 /12	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026						
Monthly Depreciation Expense	55,442	5,225	83	1,572	1,036	1,221					9,136	
Jan - December	12	12	12	12	12	12						
Depreciation Expense on 2007 Balance Add:	665,310	62,698	991	18,859	12,437	14,651					109,636	
Deprec Exp.on 2008 Addition/Retirement												
January Additions/Retirements							425					
Monthly Depreciation Rate = .0312 /12							0.0026					
Monthly Depreciation Expense							1.11					
Jan - December							11.5					
Deprec Exp.on Feb Addition/Retirement Add:							13				13	
Feb Additions/Retirements							1,168					
Monthly Depreciation Rate = .0312 /12							0.0026					
Monthly Depreciation Expense							3.04					
Feb - December							10.5					
Deprec Exp.on March Addition/Retirement Add:							32				32	
March Additions/Retirements							840					
Monthly Depreciation Rate = .0312 /12							0.0026					
Monthly Depreciation Expense							2.16					
March - December							9.5					
Deprec Exp.on April Addition/Retirement Add:							21				21	
April Additions/Retirements							2,419					
Monthly Depreciation Rate = .0312 /12							0.0026					
Monthly Depreciation Expense							6.29					
April - December							8.5					
Deprec Exp.on May Addition/Retirement Add:							53				53	
May Additions/Retirements							187					
Monthly Depreciation Rate = .0312 /12							0.0026					
Monthly Depreciation Expense							0.49					
May - December							7.5					
Deprec Exp.on June Addition/Retirement Add:							4				4	
June Additions/Retirements							16,922					
Monthly Depreciation Rate = .0312 /12							0.0026					
Monthly Depreciation Expense							44.00					
June - December							6.5					
Deprec Exp.on Oct. Addition/Retirement Add:							286				286	
Oct. Additions/Retirements							91,340					
Monthly Depreciation Rate = .0312 /12							0.0026					
Monthly Depreciation Expense							237.48					
Oct - December							2.5					
Deprec Exp.on Nov Addition/Retirement Add:							594				594	
Dec Additions/Retirements												
Monthly Depreciation Rate = .0312 /12												
Monthly Depreciation Expense												
December												
Deprec Exp.on Dec Addition/Retirement											-	
Plant In Service at 12/31/08	21,324,028	2,009,542	31,762	604,451	398,628	469,590	113,302				3,627,276	24,951,303
Accumulated provision for Depreciation at 12/31/08	9,137,697	901,478	4,914	60,594	31,454	21,767	1,002				1,021,208	10,158,905
Net Plant NBV @ 12/31/08	12,186,331	1,108,064	26,849	543,857	367,174	447,823	112,300				2,606,067	14,792,398
Depreciation expense 2008	665,310										110,638	776,948

	Pre - 97 (PTF)	Post - 96 (PTF)										Total Pre 97 and Post 96 (PTF)
		Pre -2004	2004 Additions	2005 Additions	2006 Additions	2007 Additions	2008 Additions	2009 Additions			Total Post - 96	
Plant In Service at 12/31/08	21,324,028	2,009,542	31,762	604,451	398,628	469,590	113,302	-			3,627,276	24,951,303
Accumulated provision for Depreciation												

	Pre - 97	Post - 96										Total Pre 97 and Post 96
		Pre -2004	2004 Additions	2005 Additions	2006 Additions	2007 Additions	2008 Additions	2009 Additions	2010 Additions	2011 Additions	Total Post - 96	
Plant in Service at 12/31/03	21,996,233	2,009,542	-	-	-	-	-	-	-	-	2,009,542	24,005,775
at 12/31/08	9,137,697	901,478	4,914	60,594	31,454	21,767	1,002	-	-	-	1,021,208	10,158,905
Net Plant NBV @ 12/31/08	12,186,331	1,108,064	26,849	543,857	367,174	447,823	112,300	-	-	-	2,606,067	14,792,398

2009											
Additions											
January								488,111			
February								(127)			
March								351,925			
April								65,614			
May								277,561			
June								55,184			
July								99,363			
August								6,169			
September								39,364			
October								(56,073)			
November								1,117			
December								11,978			
Retirements											
Jan - Mar								(78,946)			
Oct - Dec								(1,941,328)			
Removal											
Jan - Mar								(3,000)			
Oct - Dec								(1,036,877)			
Adjustment											
Monthly Depreciation Expense											
Depreciable Balance @ 12/31/09	21,324,028	2,009,542	31,762	604,451	398,628	469,590	113,302				3,627,276
Monthly Depreciation Rate = .0312 /12	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026				
Monthly Depreciation Expense	55,442	5,225	83	1,572	1,036	1,221	295				9,431
Jan - December	12	12	12	12	12	12	12				
Depreciation Expense on 2008 Balance	665,310	62,698	991	18,859	12,437	14,651	3,535				113,171
Add:											
Deprec Exp.on Jan Addition/Retirement											
January Additions/Retirements	(59,467)							488,111			
Monthly Depreciation Rate = .0312 /12	0.0026							0.0026			
Monthly Depreciation Expense	(155)							1,269.09			
Jan - December	11.5							11.5			
Deprec Exp.on Feb Addition/Retirement	(1,778)							14595			14,595
Add:											
Feb Additions/Retirements	-							(127)			
Monthly Depreciation Rate = .0312 /12	0.0026							0.0026			
Monthly Depreciation Expense	-							(0.33)			
Feb - December	10.5							10.5			
Deprec Exp.on March Addition/Retirement								(3)			(3)
Add:											
March Additions/Retirements	(21,827)							351,925			
Monthly Depreciation Rate = .0312 /12	0.0026							0.0026			
Monthly Depreciation Expense	(57)							915.01			
March - December	(539)							9.5			
Deprec Exp.on April Addition/Retirement								8,693			8,693
Add:											
April Additions/Retirements	2,349							65,614			
Monthly Depreciation Rate = .0312 /12	0.0026							0.0026			
Monthly Depreciation Expense	6							170.60			
April - December	8.5							8.5			
Deprec Exp.on May Addition/Retirement	52							1,450			1,450
Add:											
May Additions/Retirements	-							277,561			
Monthly Depreciation Rate = .0312 /12	0.0026							0.0026			
Monthly Depreciation Expense	-							721.66			
May - December	7.5							7.5			
Deprec Exp.on June Addition/Retirement								5,412			5,412
Add:											
June Additions/Retirements	-							55,184			
Monthly Depreciation Rate = .0312 /12	0.0026							0.0026			
Monthly Depreciation Expense	-							143.48			
June - December	6.5							6.5			
Deprec Exp.on Oct. Addition/Retirement								933			933
Add:											
July Additions/Retirements	-							99,363			
Monthly Depreciation Rate = .0312 /12	0.0026							0.0026			
Monthly Depreciation Expense	-							258.34			
July - December	5.5							5.5			
Deprec Exp.on Oct. Addition/Retirement								1,421			1,421
Add:											
August Additions/Retirements	-							6,169			
Monthly Depreciation Rate = .0312 /12	0.0026							0.0026			
Monthly Depreciation Expense	-							16.04			
August - December	4.5							4.5			
Deprec Exp.on Oct. Addition/Retirement								72			72
Add:											
Sept Additions/Retirements	-							39,364			
Monthly Depreciation Rate = .0312 /12	0.0026							0.0026			
Monthly Depreciation Expense	-							102.35			
Sept - December	3.5							3.5			
Deprec Exp.on Oct. Addition/Retirement								358			358
Add:											
Oct Additions/Retirements	(1,941,328)							(56,073)			
Monthly Depreciation Rate = .0312 /12	0.0026							0.0026			
Monthly Depreciation Expense	(5,047)							(145.79)			

[illegible]

Change in Plant in Service
Year 2010

Accounting

Month		Additions	Retirements	Removal	PTF	NPTF	GSU-C	FUT	GSU-C,FUT	GSU	SS	52	Total
January	Misc tools	3,447			3,447				3,447				3,447
March	Relay Upgrade 394 Line Terminal	227,714			227,714				227,714				227,714
March	Relay Upgrade 394 Line Terminal	227,714			227,714				227,714				227,714
March	SCADA UP REDAC Supv for PTF	(71)			(71)				(71)	-	-		(71)
April	Foundation for Newington Line terminal structures EY 7174, 7176		(227,913)		(227,913)				(227,913)				(227,913)
April	Gas cart/ tools	3,481			3,481				3,481				3,481
April	Foundation for Newington Line terminal structures	303,154			303,154				303,154				303,154
May	SCADA UP REDAC Supv for PTF	452			452				452				452
May	Termination Yard-Lightning Arrestors #2 EY Nbr 7175	91,104	(113,956)		(22,852)				(22,852)				(22,852)
	Reliability Upgrade Project	-			-				-			552,959	552,959
	Total	856,995	(341,869)	-	515,126	-	-	-	515,126	-	-	552,959	1,068,085
	Misc tools	3,447	-	-	3,447	-	-	-	3,447	-	-		3,447
	Gas cart/tools	3,481	-	-	3,481	-	-	-	3,481	-	-	-	3,481
	Relay Upgrade 394 Line Terminal	227,714	-	-	227,714	-	-	-	227,714	-	-	-	227,714
	Relay Upgrade 394 Line Terminal	227,714	-	-	227,714	-	-	-	227,714	-	-	-	227,714
	Termination Yard-Lightning Arrestors #2 EY Nbr 7175	91,104	(113,956)		(22,852)				(22,852)				(22,852)
	Foundation for Newington Line terminal structures EY 7174, 7176	303,154	(227,913)		75,241				75,241				75,241
	SCADA UP REDAC Supv for PTF	381	-	-	381	-	-	-	381	-	-	-	381
	Total Excl Reliability Upgrade Project (5-Breaker Project)	856,995	(341,869)	-	515,126	-	-	-	515,126	-	-	-	515,126
	Reliability Upgrade Project (5-Breaker Project)				-				-			552,959	552,959
	Total Incl Reliability Upgrade Project (5-Breaker Project)	856,995	(341,869)	-	515,126	-	-	-	515,126	-	-	552,959	1,068,085

New Hampshire Transmission, LLC
June-December 2010

June-December 2010		PTF Only				Non PTF			LNS		Project 52	Grand Total	
		Additions	Retirements	Removal	Total PTF	NPTF	GSU-C	FUT	PTF, NPTF GSU-C,FUT	GSU			SS
June	CIAC				-				-			(17,052,629)	(17,052,628.63)
September	Retire Sequence Event Recorder - EY 5652		(28,566.75)		(28,566.75)			(25,179.64)	(25,179.64)				(53,746.39)
September	Retire Fault Recorder / Oscilligraph - EY 3501		(87,281.97)		(87,281.97)			(13,436.60)	(13,436.60)				(100,718.57)
October	Adj- Contractor / Consultant invoice - MEPP1				-				-			(2,170,306)	(2,170,306.00)
November	APP Engineering Model Recorder	390,061.28			390,061.28				-		130,020.43		520,081.71
November	Relay Protection Equipment	474,811.65			474,811.65				-				474,811.65
November	Adj- Contractor / Consultant invoice - PGS				-				-			5,078.79	5,078.79
December	Adjustment to removal cost				-				-			991,493.00	991,493.00
December	Cap interest paid by NextEra Energy Seabrook				-				-			(245,430.00)	(245,430.00)
Total		864,872.93	(115,848.72)	-	749,024.21	-	-	(38,616.24)	(38,616.24)	-	130,020.43	(18,471,792.84)	(17,631,364.45)

Amounts shown prior to June 1, 2010 reflect amounts recorded by FPL prior to transfer of the assets to NHT

ASSUMES: Tools and TIE Equip additions of \$99,950 (at 100% value) in January 2004 split as per ABB
ASSUMES: NO retirements, salvage or removal for 2004
ASSUMES: Retirements and Removal in 2005 & 2006 = 100% PTF per ABB study
ASSUMES: Additions in 2005 & 2006 replaced items retired in 2005 & 2006 and are 100% PTF
ASSUMES: Annual depreciation rate of 3.12% applied to all properties.

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Plant Data Support 3

246			88,22889%			PTF		PTF		Total	Memo Only					
247	<u>Depreciation Expense for 2011</u>	MEMO ONLY				PTF	NPTF	NPTF	GSU-C	FUT	LNS	GSU	GSU-Diff	SS	Project 52	Total
248																
249	January-11	\$ 173,860	153,395	66,331	2,206	68,537	6,956	791	76,285				207	4,610	72,293	153,395
250	February-11	\$ 174,004	153,522	66,441	2,211	68,652	6,969	791	76,412				207	4,610	72,293	153,522
251	March-11	\$ 173,971	153,493	66,416	2,210	68,625	6,966	791	76,383				207	4,610	72,293	153,493
252	April-11	\$ 173,971	153,493	66,415	2,210	68,625	6,966	791	76,382				207	4,610	72,293	153,493
253	May-11	\$ 170,673	150,583	66,416	2,210	68,625	4,056	791	73,473				207	4,610	72,293	150,583
254	June-11	\$ 186,705	164,728	67,599	2,238	69,837	5,282	791	75,911				207	4,679	83,931	164,728
255	July-11	\$ 175,778	155,087	67,472	2,215	69,687	5,422	791	75,901				207	4,747	74,233	155,087
256	August-11	\$ 175,778	155,087	67,472	2,215	69,687	5,422	791	75,901				207	4,747	74,233	155,087
257	September-11	\$ 176,737	155,933	68,318	2,215	70,533	5,422	791	76,746				207	4,747	74,233	155,933
258	October-11	\$ 178,097	157,133	69,384	2,218	71,602	5,422	791	77,815				338	4,747	74,233	157,133
259	November-11	\$ 175,477	154,821	66,938	2,222	69,160	5,422	791	75,373				468	4,747	74,233	154,821
260	December-11	\$ 165,129	145,691	67,039	2,225	69,265	19,464	791	89,520				468	4,747	50,955	145,691
261	Total Jan-Dec 2011	2,100,180	1,852,966	0	806,241	26,594	832,835	83,769	9,496	926,100	0	3,139	56,213	867,513	1,852,966	
262																
263			88,22889%			PTF		PTF		Total	Memo Only					
264	As of December 31, 2011	100%				NPTF		NPTF	GSU-C	FUT	LNS	GSU	GSU-Diff	SS	Project 52	Total
265		MEMO ONLY														
266	Plant in Service (per ABB Study - adjusted)	\$ 79,007,455	\$ 69,707,401	\$ 25,869,818	\$ 857,471	\$ 26,727,289	\$ 2,094,384	\$ 304,353	\$ 29,126,026	\$ 16,966,982	\$ 124,816	\$ 1,834,789	\$ 28,550,979	\$ 48,052,613		
267																
268	Accumulated Depreciation	\$ 50,407,848	44,474,285	7,814,490	153,523	7,968,013	755,609	98,775	8,822,398	8,361,236	8,540	818,903	2,752,450	\$ 18,011,077		
269	Net Plant	\$ 28,599,607	\$ 25,233,116	\$ 18,055,328	\$ 703,948	\$ 18,759,276	\$ 1,338,775	\$ 205,577	\$ 20,303,628	\$ 8,605,747	\$ 116,275	\$ 1,015,886	\$ 25,798,529	\$ 30,041,537		
270																
271	Jan- Dec 2011 Changes	1,750,311	1,544,280	1,360,065	9,764	1,369,829	21,159	-	1,390,988	-	100,514.08	52,777.92		1,544,280		
272	CIAC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
273	Removal	(625,972)	(552,288)	-	-	-	-	-	-	-	-	-	-	-	(552,288)	-
274	Scrap sale	-	-	-	-	-	-	-	-	-	-	-	-	-	7,734	-
275	Adst to classif.(retirement 2010)***	-	-	38,617	-	-	-	-	-	-	-	-	(38,617)	-	(38,617)	-
276	Adjustment to acc. Deprec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
277	Retirements	(15,862,264)	(13,995,100)	(1,025,614)	-	(1,025,614)	(599,593)	-	(1,625,207)	-	-	-	-	-	(12,369,893)	(1,625,207)
278	Depreciation	2,100,180	1,852,966	806,241	26,594	832,835	83,769	9,496	926,100	0	3,139	56,213	867,513	965,452		
279																
280																
281	*** This line is only to fix this file. In Dec. 10 there was \$38,617 included in PTF. FERC was reported correctly															

	2011	FERC	\$ 1,959,605
Plant in Service Components	Component	Account	
Transmission Plant in Service	\$ 59,636,610	102	
Electric Plant in Service Subfunctional Category:			
Pool transmission Facilities (PTF)	\$ 25,869,818		
Non -Pool Transmission Facilities (NPTF)	3,256,208		
Reliability Upgrade (Pool Supported PTF/PTF/NPTF Classification to be Determined)	26,550,979		
Amounts excluded under the LNS Tariff	1,959,605		
Total Transmission Plant in Service	\$ 59,636,610		
Accumulated provision for Depreciation Transmission plant	\$ 12,402,291	108	
Accumulated Provision for Depreciation Subfunctional Category:			
Pool transmission Facilities (PTF)	\$ 7,853,105		
Non -Pool Transmission Facilities (NPTF)	969,292		
Reliability Upgrade (Pool Supported PTF/PTF/NPTF Classification to be Determined)	2,752,451		
Amounts excluded under the LNS Tariff	627,443		
Total Accumulated Provision	\$ 12,402,291		
Accumulated deferred taxes	\$ 10,304,055	262	
Accumulated deferred Taxes Subfunctional Category:			
Accumulated deferred Taxes -Transmission Related	\$ 10,304,055		
Accumulated deferred Taxes - Other	27,947	283	
Total Accumulated Deferred Taxes	\$ 10,332,002		

Plant Data Support for EPL-NED's / NHT's Seabrook Reliability Upgrade 5-Breaker Project

	Total Cost 2009	FPL-NED Share	In-Service Yr.	FPL-NED's Cost 2009\$	Adjusted 2010 Total Cost	NHT Share	
Facilities Description -Seabrook Reliability Upgrade - 5 Breaker Project	100%	88.22889%		88.22889%		88.22889%	
GSU Breakers (11 & 12)	20,665,210	18,232,685	2009	10,120,753	24,517,910	21,631,879	
Structure	13,651,543	12,044,605	2009	12,044,605	13,594,319	11,994,117	
Newington Replacement Breakers / Associated Bus	13,394,329	11,817,668	2009	11,817,668	14,602,797	12,883,886	
Breaker 25	5,015,540	4,425,155	2009	4,425,155	4,981,266	4,394,916	
Bus 1 Connection (50% Newington / 50% GSU)	3,341,790	2,948,424	2009	2,264,527	3,239,735	2,858,382	
Bus 2 Connection (50% Newington / 50% GSU)	4,018,797	3,545,740	2009	2,861,843	3,912,116	3,451,616	
Bus 5	3,326,870	2,935,260	2009	2,935,260	3,304,136	2,915,202	
	63,414,079	55,949,538		46,469,812	68,152,278	60,129,998	
							Totals Excluding DAF
Plant Cost of Direct Assignment Charges excluded from RNS and LNS Transmission Rates				2009\$ DAF	Percentage of Plant	2010\$ DAF	Percentage of Plant
	GSU	10,120,753	21.7792%		21,631,879	35.9752%	
	40% Structure	4,817,842	10.3677%		4,797,647	7.9788%	
	50% Bus 1	1,132,263	2.4366%		1,429,191	2.3768%	
	50% Bus 2	1,430,922	3.0793%		1,725,808	2.8701%	
	Total	17,501,780	37.6627%		29,584,525	49.2009%	
Plant Cost of 5-Breaker Project PTF included in RNS		RNS			RNS	Percentage of Plant	
	60% Structure	7,226,763	15.5515%		7,196,470	11.9682%	
	Newington Bkrs	11,817,668	25.4308%		12,883,886	21.4267%	
	Bkr 25	4,425,155	9.5226%		4,394,916	7.3099%	
	50% Bus 1	1,132,263	2.4366%		1,429,191	2.3768%	
	50% Bus 2	1,430,922	3.0793%		1,725,808	2.8701%	
	Total	26,032,771	56.0208%		27,630,271	45.9509%	27,630,271 90.46%
Plant Cost of 5-Breaker Project PTF included in LNS		LNS			LNS	Percentage of Plant	
	Bus 5	2,935,260	6.3165%		2,915,202	4.8482%	2,915,202 9.54%
	Total DAF+RNS+LNS	46,469,812	100.0000%		60,129,998	100.0000%	30,545,473 100%

Note: Allocation of Plant Costs between DAF, RNS and LNS is based on application of regional cost support requested from ISO-NE and is subject to ISO-NE's final determination under Schedule 12C.

Supporting information for calculatoin of FPL-NED's Annual Transmission Revenue Requirements

Derivation of Depreciation Expense				
	(a)	(b)	(c)	
Depreciation Expense Not Subject to Pending TCA Review	Percentage	Source	Pool-Supported PTF	Source
Total PTF Related	100.00%	NA	\$ 806,242	Form 1
Pre-97 PTF	72.09%	NA	581,223	Plant Data Support 1
Post-96 PTF	27.91%	NA	225,019	Plant Data Support 1
Depreciation Expense	Percentage	Source	Reliability Upgrade (See Note)	
Total Pending a TCA Review (Reliability Upgrade Project)	100.00%	NA	\$ 867,513	Form 1
Pool-Supported PTF (pending TCA approval)	45.95%	Plant Data Support 4	398,630	(a) x (c)
Costs not requested to be Pool-Supported	54.05%	Plant Data Support 4	468,883	(a) x (c)

Derivation of Accumulated Depreciation Reserve					
Accumulated Depreciation Reserve Not Subject to Pending TCA Review	(a) Percentage	(b) Source	(c) Pool-Supported PTF Source		
Total PTF Related	100.00%	NA	\$	7,853,105	Form 1
Pre-97 PTF	80.00%	NA		6,282,153	Plant Data Support 1
Post-96 PTF	20.00%	NA		1,570,952	Plant Data Support 1
Accumulated Depreciation Reserve	Percentage	Source	Reliability Upgrade (See Note) Source		
Total Pending a TCA Review (Reliability Upgrade Project)	100.00%	NA	\$	2,752,451	Form 1
Pool-Supported PTF (pending TCA approval)	45.95%	Plant Data Support 4		1,264,776	(a) x (c)
Costs not requested to be Pool-Supported	54.05%	Plant Data Support 4		1,487,675	(a) x (c)

Derivation of Accumulated Deferred Income Taxes						Row /Col. Reference
Accumulated Deferred Income Taxes Not Subject to Pending TCA Review	(a) Percentage	(b) Source	(c) Pool-Supported PTF	Source		
Total PTF Related	100.00%	NA	\$ 4,481,928	Row 11. col. (c)		1
Pre-97 PTF	68.88%	NA	3,087,376	Row 12. col. (c)		2
Post-96 PTF	31.12%	NA	1,394,552	Row 13. col. (c)		3
	(a)	(b)	(c)			4
Accumulated Deferred Income Taxes	Percentage	Source	Reliability Upgrade	Source		5
Total Pending a TCA Review (Reliability Upgrade Project)	100.00%	NA	\$ 4,946,438	Row 15. col. (c)		6
Pool-Supported PTF (pending TCA approval)	90.46% Plant Data Support 4		4,474,359	Row 8(a) x Row 7(c)		7
Costs not requested to be Pool-Supported	9.54% Plant Data Support 4		472,079	Row 9(a) x Row 7(c)		8
	2011 Gross Plant	Percentages	2011 Allocated DIT			10
Gross PTF Plant In Service	\$ 25,869,818	43.38%	\$ 4,481,928			11
Gross Pre-'97 PTF Plant In Service	17,820,422	29.88%	\$ 3,087,376			12
Gross Post-'96 PTF Plant In Service (excluding Reliability Upgrade Project-52)	8,049,396	13.50%	\$ 1,394,552			13
Gross Non-PTF Plant In Service	3,256,208	5.46%	\$ 564,136			14
Gross Reliability Upgrade Plant In-Service	28,550,979	47.87%	\$ 4,946,438			15
Gross Amounts Excluded from LNS Tariff	1,959,605	3.29%	\$ 339,500			16
Total Gross Plant In Service	\$ 59,636,610	100.00%	\$ 10,332,002			17
	From NHT June 2010					18
Gross Reliability Upgrade Included in Rates	PTF ATRR File	Percentages				19
Gross Plant In Service in RNS at 12-31-2010	\$ 27,630,271	90.46%				20
Gross Plant In Service in LNS at 12-31-2011	2,915,202	9.54%				21
Total	30,545,473	100.00%				22

	Assets	NHT Form 1
ELELCTRIC UTILITY PLAN:		
Transmission Plant in service	\$	59,636,610
Electric Plant In Service Subcategory:		
Pool Transmission Facilities (PTF)	\$	25,869,818
Non-Pool Transmission Facilities (NPTF)		3,256,208
Reliability Upgrade (Pool Supported PTF/NPTF TBD)		28,550,979
Amounts excluded under the LNS Tariff		1,959,605
Total Transmission Plant In-Service	\$	59,636,610
Construction work in progress		
Accumulated Provision for Depreciation Transmission Plant	\$	12,402,291
Accumulated Provision for Depreciation Subfunctional Category:		
Pool Transmission Facilities (PTF)	\$	7,853,105
Non-Pool Transmission Facilities (NPTF)		969,292
Reliability Upgrade (Pool Supported PTF/NPTF TBD)		2,752,451
Amounts excluded under the LNS Tariff		827,443
Total Accumulated Provision	\$	12,402,291
Accumulated Deferred Taxes	\$	10,332,002
Pool Transmission Facilities (PTF)		See Data Support 5
Non-Pool Transmission Facilities (NPTF)		See Data Support 5
Reliability Upgrade (Pool Supported PTF/NPTF TBD)		See Data Support 5
Amounts excluded under the LNS Tariff (includes CIAC related)		See Data Support 5
Total Accumulated Deferred Taxes	\$	10,332,002
EXPENSES		
Property Insurance Expense	\$	39,930
Regulatory Commission Expense		29,833
Other A&G Expenses		841,423
Total Administrative and General Expenses	\$	911,186
Transmission Wages and Salaries		-
Administrative and General Wages and Salaries		104,421
Total Wages and Salaries	\$	104,421
Depreciation Expense	\$	1,852,966
Pool Transmission Facilities (PTF)		806,242
Non-Pool Transmission Facilities (NPTF)		119,859
Reliability Upgrade (Pool Supported PTF/NPTF TBD)		867,513
Amounts excluded under the LNS Tariff		59,352
	\$	1,852,966
FERC Account		
165	Prepayments	69,838
403	Depreciation Expense - Total	\$ 1,852,966
	PTF Depreciation Expense	\$ 806,242
	Non-PTF Depreciation Expense	\$ 119,859
	Reliability Upgrade (Pool-Supported amount not yet determined)	\$ 867,513
	Non-Recoverable under RNS or LNS Formula Rats	\$ 59,352
	Total Depreciation Expense	\$ 1,852,966
408.1	Taxes Other than Income Taxes - Payroll Taxes	0
408.1	Taxes Other than Income Taxes - Property Taxes	1,145,452
408.1	Regulatory Commission Assessments	-
409.1	Income Taxes	
409.2	Income Taxes	
410.1	Provision for Deferred Income Taxes	
411.1	Provision for Deferred Income Taxes - Credit	
419	Interest Income	
431	Interest Expense	
456	Tariff Revenue	
562	Station Expense - Support Payments	726,518
562	Station Expense - Other	72,855
562	Station Expense - Other	19,148
570	Maintenance of Station Equipment	1,789,933
920	Administrative and General Salaries	31,651
921	A&G - Office Supplies & Expenses	7,862
922	A&G / Overhead	-
923	Outside Services	784,092
924	Property Insurance	39,930
925	Employee Worker Comp Ins.	5,703
926	Pension & Welfare	-
928	Regulatory Commission Expense	29,833

INTEREST PAID BY NHT ON LONG TERM DEBT DURING 2011

End Date	Draws	Total Outstanding	Interest Rate	Daily Interest	# Days	Interest	Interest Accrued-to-Date
1/31/2011		\$ 24,505,285.00	0.040426202	2751.821108	31	\$ 85,306.45	\$ 85,306.45
1/31/2011	\$810,607.00	\$ 25,315,892.00					\$ 85,306.45
2/28/2011		\$ 25,315,892.00	0.043437447	\$ 3,054.60	28	\$ 85,528.93	\$ 170,835.39
3/31/2011		\$ 25,315,892.00	0.042622598	2997.303038	31	\$ 92,916.39	\$ 263,751.78
4/30/2011		\$ 25,315,892.00		Interest received in April		\$ (263,751.78)	\$ 0.00
4/30/2011		\$ 25,315,892.00	0.042402114	\$ 2,981.80	30	\$ 89,453.95	\$ 89,453.95
5/31/2011		\$ 25,315,892.00	0.043240277	\$ 3,040.74	31	\$ 94,262.92	\$ 183,716.87
6/30/2011		\$ 25,315,892.00	0.044315855	3116.376129	30	\$ 93,491.28	\$ 277,208.15
7/31/2011		\$ 25,315,892.00		Interest received in July		\$ (277,208.15)	\$ 0.00
7/31/2011		\$ 25,315,892.00	0.043763191	\$ 3,077.51	31	\$ 95,402.86	\$ 95,402.86
8/31/2011		\$ 25,315,892.00	0.039685699	\$ 2,790.77	31	\$ 86,514.01	\$ 181,916.88
9/30/2011		\$ 25,315,892.00	0.025668896	1805.086096	30	\$ 54,152.58	\$ 236,069.46
10/24/2011		\$ 25,315,892.00		Interest received in October		\$ (236,069.46)	\$ 0.00
10/31/2011		\$ 25,315,892.00	0.037374529	\$ 2,628.25	31	\$ 81,475.71	\$ 81,475.71
11/30/2011		\$ 25,315,892.00	0.037105878	\$ 2,609.36	30	\$ 78,280.70	\$ 159,756.41
12/31/2011		25315892	0.03886149	2732.814693	31	\$ 84,717.26	\$ 244,473.67

p. 1

sum Jan-Dec 2011

0.478904178

Average 2011

0.039908681

Note: On Dec. 31, 2011, balance of loan was adjusted to \$16,080,443

ISO-NE Tariff Billing
PTO Annual Transmission Revenue Requirements
per OATT Attachment F

Submitted on: 31-Jul-12

Revenue Requirements for (year): June 1, 2012 - May 31, 2013

Customer: Northeast Utilities System Companies'

Customer's NABs Number: # 34

Name of Participant responsible for customer's billing: Northeast Utilities Transmission

DUNS number of Participant responsible for customer's billing: # 95 - 910 - 8929

	<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>
Total of Attachment F - Sections A through I	= <u>89,253,571</u> (a)	<u>476,826,896</u> (g)
Total of Attachment F - Section J - Support Revenue	<u>1,926,428</u> (b)	<u>-</u> (h)
Total of Attachment F - Section K - Support Expense	<u>3,205,933</u> (c)	<u>-</u> (i)
Total of Attachment F - Section (L through O)	<u>(4,670,095)</u> (d)	<u>9,132,803</u> (j)
Sub Total - Sum (A through I) - J + K + (L through O)	<u>85,862,981</u> (e)=(a)-(b)+(c)+(d)	<u>485,959,699</u> (k)=(g)-(h)+(i)+(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	<u>N/A</u> (f)	<u>61,506,000</u> (l)
Annual True-up (per Attachment C to Attachment F Implementation Rule)	<u>(8,091,691)</u> (m)	<u>(23,884,713)</u> (n)
Adjusted Sub Total (Sub Total + True-up)	<u>77,771,290</u> (o) = (e)+(f)+(m)	<u>523,580,986</u> (p) = (k)+(l)+(n)
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements & Post Revenue Requirements Subtotals, Forecasted Revenue Requirements, and True-ups (including interest)		<u>601,352,276</u> (q) = (o) + (p)

Northeast Utilities System Companies'
Annual Revenue Requirements of PTF Facilities -2011
for Rates billed June 1, 2012 - May 31, 2013
Pre-1997

		Attachment F					
		Reference	CL&P	PSNH	WMECO	Total	Reference
Line No.	I. INVESTMENT BASE	Section:					
1	Transmission Plant	(A)(1)(a)	365,003,371	90,490,711	60,534,512	516,028,594	W/S 3A,3B,3C line 1
2	General Plant	(A)(1)(b)	12,505,734	7,488,975	3,485,303	23,480,012	W/S 3A,3B,3C line 2
3	Plant Held For Future Use	(A)(1)(c)	159,508	1,728,539	9,573,144	11,461,191	W/S 3A,3B,3C line 4
4	Total Plant (Lines 1+2+3)		377,668,613	99,708,225	73,592,959	550,969,797	
5	Accumulated Depreciation	(A)(1)(d)	66,048,597	19,557,778	12,148,408	97,754,783	W/S 3A,3B,3C line 7
6	Accumulated Deferred Income Taxes	(A)(1)(e)	34,872,687	14,268,381	9,266,755	58,407,823	W/S 3A,3B,3C line 10
7	Loss On Reacquired Debt	(A)(1)(f)	900,241	348,870	17,571	1,266,682	W/S 3A,3B,3C line 11
8	Other Regulatory Assets	(A)(1)(g)	2,660,851	1,372,202	190,565	4,223,618	W/S 3A,3B,3C line 15
9	Net Investment (Line 4-5-6+7+8)		280,308,421	67,603,138	52,385,932	400,297,491	
10	Prepayments	(A)(1)(h)	500,453	940,421	66,982	1,507,856	W/S 3A,3B,3C line 16
11	Materials & Supplies	(A)(1)(i)	4,514,506	2,721,624	232,348	7,468,478	W/S 3A,3B,3C line 17
12	Cash Working Capital	(A)(1)(j)	1,400,877	523,123	360,353	2,284,353	W/S 3A,3B,3C line 24
13	Total Investment Base (Line 9+10+11+12)		286,724,257	71,788,306	53,045,615	411,558,178	
II.	REVENUE REQUIREMENTS						
14	Investment Return and Income Taxes	(A)	36,493,117	8,944,895	6,564,872	52,002,884	W/S 2A,2B,2C
15	Depreciation Expense	(B)	8,867,702	2,020,188	1,107,774	11,995,664	W/S 4A,4B,4C line 3
16	Amortization of Loss on Reacquired Debt	(C)	65,604	35,104	2,735	103,443	W/S 4A,4B,4C line 4
17	Investment Tax Credit	(D)	(84,117)	(1,718)	(11,379)	(97,214)	W/S 4A,4B,4C line 5
18	Property Tax Expense	(E)	5,136,278	2,129,214	882,892	8,148,384	W/S 4A,4B,4C line 8
19	Payroll Tax Expense	(F)	68,449	22,767	13,875	105,091	W/S 4A,4B,4C line 19
20	Operation & Maintenance Expense	(G)	5,227,172	1,947,301	1,187,508	8,361,981	W/S 4A,4B,4C line 17
21	Administrative & General Expense	(H)	5,678,048	1,643,762	1,311,528	8,633,338	W/S 4A,4B,4C line 18
22	Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	
23	Transmission Support Revenue	(J)	(1,526,417)	(400,011)	-	(1,926,428)	W/S 7
24	Transmission Support Expense	(K)	1,828,212	993,935	383,786	3,205,933	W/S 7
25	Transmission Related Expense from Generators	(L)	-	-	-	-	
26	Transmission Related Taxes and Fees Charge	(M)	2,086,170	26,324	3,885	2,116,379	Attachment B line 14
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(264,509)	(55,529)	(38,370)	(358,408)	Attachment C line 9
28	Transmission Rents Received from Electric Property	(O)	(4,312,566)	(1,759,216)	(356,284)	(6,428,066)	
29	Total Revenue Requirements (Line 14 thru 28)		59,263,143	15,547,016	11,052,822	85,862,981	

Northeast Utilities System Companies'
Annual Revenue Requirements of PTF Facilities -2011
for Rates billed June 1, 2012 - May 31, 2013
Post-1996

		Attachment F					
		Reference	CL&P	PSNH	WMECO	Total	Reference
Line No.	I. INVESTMENT BASE	Section:					
1	Transmission Plant	(A)(1)(a)	1,870,692,407	364,557,343	151,347,756	2,386,597,506	W/S 3A,3B,3C line 1
2	General Plant	(A)(1)(b)	64,093,490	30,170,664	8,713,927	102,978,081	W/S 3A,3B,3C line 2
3	Plant Held For Future Use	(A)(1)(c)	817,501	6,963,727	23,934,701	31,715,929	W/S 3A,3B,3C line 4
4	Total Plant (Lines 1+2+3)		1,935,603,398	401,691,734	183,996,384	2,521,291,516	
5	Accumulated Depreciation	(A)(1)(d)	338,507,536	78,791,975	30,373,357	447,672,868	W/S 3A,3B,3C line 7
6	Accumulated Deferred Income Taxes	(A)(1)(e)	178,726,998	57,482,706	23,168,670	259,378,374	W/S 3A,3B,3C line 10
7	Loss On Reacquired Debt	(A)(1)(f)	4,613,852	1,405,484	43,931	6,063,267	W/S 3A,3B,3C line 11
8	Other Regulatory Assets	(A)(1)(g)	13,637,203	5,528,159	476,449	19,641,811	W/S 3A,3B,3C line 15
9	Net Investment (Line 4-5-6+7+8)		1,436,619,919	272,350,696	130,974,737	1,839,945,352	
10	Prepayments	(A)(1)(h)	2,564,888	3,788,653	167,468	6,521,009	W/S 3A,3B,3C line 16
11	Materials & Supplies	(A)(1)(i)	23,137,421	10,964,546	580,915	34,682,882	W/S 3A,3B,3C line 17
12	Cash Working Capital	(A)(1)(j)	6,986,333	1,808,405	781,009	9,575,747	W/S 3A,3B,3C line 24
13	Total Investment Base Excluding CWIP (Line 9+10+11+12)		1,469,308,561	288,912,300	132,504,129	1,890,724,990	
14	NEEWS Construction Work In Progress	(A)(1)(l)	128,817,356		264,352,233	393,169,589	
15	Total Investment Base Including CWIP (Line 13+14)		1,598,125,917	288,912,300	396,856,362	2,283,894,579	
II. REVENUE REQUIREMENTS							
16	Investment Return and Income Taxes	(A)	186,943,067	35,998,761	16,396,193	239,338,021	W/S 2A,2B,2C
17	Investment Return and Income Taxes-CWIP		16,389,690		32,711,210	49,100,900	W/S 2A,2B,2C
18	Depreciation Expense	(B)	45,448,111	8,138,682	2,769,648	56,356,441	W/S 4A,4B,4C line 3
19	Amortization of Loss on Reacquired Debt	(C)	336,228	141,422	6,837	484,487	W/S 4A,4B,4C line 4
20	Investment Tax Credit	(D)	(431,113)	(6,923)	(28,450)	(466,486)	W/S 4A,4B,4C line 5
21	Property Tax Expense	(E)	26,324,083	8,577,918	2,207,400	37,109,401	W/S 4A,4B,4C line 8
22	Payroll Tax Expense	(F)	350,808	91,721	34,689	477,218	W/S 4A,4B,4C line 19
23	Operation & Maintenance Expense	(G)	26,789,936	7,845,050	2,968,998	37,603,984	W/S 4A,4B,4C line 17
24	Administrative & General Expense	(H)	29,100,726	6,622,188	3,279,073	39,001,987	W/S 4A,4B,4C line 18
25	Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	
26	Transmission Related Expense from Generators	(L)	-	-	-	-	
27	Transmission Related Taxes and Fees Charge	(M)	10,691,889	106,052	9,714	10,807,655	Attachment B line 16
28	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(1,355,267)	(223,654)	(95,931)	(1,674,852)	Attachment C line 10
29	Total Revenue Requirements (Line 16 thru 28)		340,588,158	67,291,217	60,259,381	468,138,756	

Northeast Utilities System Companies'
Annual Revenue Requirements of Incremental Return -2011
for Rates billed June 1, 2012 - May 31, 2013
Post-2003

Line	I. INVESTMENT BASE	CL&P	PSNH	WMECO	Total	Reference
1	Transmission Plant	\$ 1,536,093,122	\$ 124,372,749	\$ 12,358,222	\$ 1,672,824,093	Attachment D,D1,D2
2	Accumulated Depreciation	\$ 123,860,340	\$ 11,788,446	\$ 1,428,674	\$ 137,077,460	Attachment D,D1,D2
3	Accumulated Deferred Income Taxes	\$ 104,119,591	\$ 11,583,153	\$ 1,820,577	\$ 117,523,321	
4	Net Investment (Line 1-2-3)	\$ 1,308,113,191	\$ 101,001,150	\$ 9,108,971	\$ 1,418,223,312	
	II. <u>INCREMENTAL RETURN</u>					
5	Incremental Revenue Requirements	<u>\$ 10,967,221</u>	<u>\$ 883,053</u>	<u>\$ 76,433</u>	<u>\$ 11,926,707</u>	W/S 2A,2B,2C Post 2003

Northeast Utilities System Companies'
Annual Revenue Requirements of Incremental Return -2011
for Rates billed June 1, 2012 - May 31, 2013
M-N Advanced Technology

Line	I. <u>INVESTMENT BASE</u>	<u>CL&P</u>	<u>Reference</u>
1	Transmission Plant	\$ 420,584,588	Attachment E
2	Accumulated Depreciation	\$ 22,016,295	Attachment E
3	Accumulated Deferred Income Taxes	\$ 20,645,536	
4	Net Investment (Line 1-2-3)	\$ 377,922,757	
	II. <u>INCREMENTAL RETURN</u>		
5	Incremental Revenue Requirements	<u>\$ 1,457,270</u>	w/s 2A M-N Adv Tech

Northeast Utilities System Companies'
Annual Revenue Requirements of Incremental Return -2011
for Rates billed June 1, 2012 - May 31, 2013
NEEWS

Line	I. <u>INVESTMENT BASE</u>	<u>CL&P</u>	<u>WMECO</u>	<u>Total</u>	<u>Reference</u>
1	Transmission Plant	\$ 12,736,169	\$ 28,435,318	\$ 41,171,487	Attachment F
2	Accumulated Depreciation	\$ 637,850	\$ 351,700	\$ 989,550	Attachment F
3	Accumulated Deferred Income Taxes	\$ 2,832,851	\$ 7,397,171	\$ 10,230,022	
4	Net Investment Excluding CWIP(Line 1-2-3)	\$ 9,265,468	\$ 20,686,447	\$ 29,951,915	
5	NEEWS Construction Work In Progress	\$ 128,817,356	\$ 264,352,233	\$ 393,169,589	Attachment F
6	Net Investment Including CWIP(Line 4+5)	<u>\$ 138,082,824</u>	<u>\$ 285,038,680</u>	<u>\$ 423,121,504</u>	
	II. <u>INCREMENTAL RETURN</u>				
7	Incremental Revenue Requirements	\$ 96,324	\$ 217,828	\$ 314,152	w/s 2A NEEWS
8	Incremental Revenue Requirements-CWIP	\$ 1,339,185	\$ 2,783,629	\$ 4,122,814	w/s 2A NEEWS
9	Total Incremental Revenue Requirements (line 7+8)	<u>\$ 1,435,509</u>	<u>\$ 3,001,457</u>	<u>\$ 4,436,966</u>	

Northeast Utilities System Companies'
Forecasted Transmission Revenue Requirements of PTF Facilities - 2012 Estimated
for Rates billed June 1, 2012 - May 31, 2013
Post-1996

I. FORECASTED TRANSMISSION REVENUE REQUIREMENTS		Attachment F Reference	CL&P	PSNH	WMECO	Total NU	Reference
Line No.							
1	Forecasted Transmission Plant Additions (excl. Localized)	App. C	\$ 53,194,000	\$ 49,302,000	\$ 162,395,000	\$ 264,891,000	Attachment G
2	Carrying Charge Factor (line 18)	App. C	16.83%	18.49%	18.26%		
3	Forecasted Transmission Revenue Requirements (Lines 1 * 2)		\$ 8,953,000	\$ 9,116,000	\$ 29,653,000	\$ 47,722,000	
4	Forecasted NEEWS CWIP		\$ 77,552,000		\$ 23,199,000	\$ 100,751,000	
5	NEEWS Cost of Capital Rate (line 21)		13.76%		13.42%		
6	Forecasted Transmission Rev. Req. for CWIP (Lines 4 * 5)		\$ 10,671,000		\$ 3,113,000	\$ 13,784,000	
7	Total Forecasted Transmission Revenue Requirements (Lines 3 + 6)		\$ 19,624,000	\$ 9,116,000	\$ 32,766,000	\$ 61,506,000	
II. CARRYING CHARGE FACTOR (Post 96) (*)							
8	Investment Return and Income Taxes	(A)	\$ 186,943,067	35,998,761	16,396,193	239,338,021	W/S 1B line 14
9	Depreciation Expense	(B)	45,448,111	8,138,682	2,769,648	56,356,441	W/S 1B line 15
10	Amortization of Loss on Reacquired Debt	(C)	336,228	141,422	6,837	484,487	W/S 1B line 16
11	Investment Tax Credit	(D)	(431,113)	(6,923)	(28,450)	(466,486)	W/S 1B line 17
12	Property Tax Expense	(E)	26,324,083	8,577,918	2,207,400	37,109,401	W/S 1B line 18
13	Payroll Tax Expense	(F)	350,808	91,721	34,689	477,218	W/S 1B line 19
14	Operation & Maintenance Expense	(G)	26,789,936	7,845,050	2,968,998	37,603,984	W/S 1B line 20
15	Administrative & General Expense	(H)	29,100,726	6,622,188	3,279,073	39,001,987	W/S 1B line 21
16	Total Expenses (Lines 8 thru 15)		\$314,861,846	\$67,408,819	\$27,634,388	\$409,905,053	
17	PTF Transmission Plant		\$1,870,692,407	\$364,557,343	\$151,347,756	\$2,386,597,506	W/S 1B line 1
18	Carrying Charge Factor (Lines 16/17)		16.83%	18.49%	18.26%	17.18%	
19	Cost of Capital Rate - 11.64% ROE		12.72%		12.37%		W/S 2A, 2C
20	Cost of Capital Rate - 1.25% bp ROE adder for NEEWS		1.04%		1.05%		W/S 2A, 2C
21	NEEWS Cost of Capital Rate		13.76%		13.42%		

(*) The Carrying Charge Factor shall reflect the most recent calendar year data used in determining Post-1996 Annual Transmission Revenue Requirements and shall equal the sum of Attachment F Sections II.A through II. H divided by PTF Transmission Plant.

Northeast Utilities System Companies'
Transmission Revenue Requirements of PTF Facilities- 2011 True-up
for Rates billed June 1, 2012 - May 31, 2013
Pre-1997 & Post-1996

Line I.	ANNUAL TRUE-UP	Pre-1997	Post-1996	TOTAL	
1	Transmission Revenue Requirements (as billed)	93,691,165	509,062,792	602,753,957	ATRR - Prior Year
2	True-up 2011 Actual Annual RR @ 11.64% ROE	85,862,981	485,959,699	571,822,680	PTF Pre and Post on ATRR
3	Total Rate Year Surcharge/(Refund) (Line 2 - 1)	(7,828,184)	(23,103,093)	(30,931,277)	

Northeast Utilities System Companies'
FERC Interest Calculation associated with Surcharge / (Refund)
Transmission Revenue Requirements of PTF Facilities
Pre-1997 & Post-1996

Pre Post	Surcharge / (Refund)		FERC Monthly Interest Rate	Interest		variance
	(7,828,184)	(23,103,093)				
Initial Billing Period	Pre-1997 Balance	Post-1996 Balance		Pre-1997 Interest	Post-1996 Interest	
June 2011	\$ (7,828,184)	\$ (23,103,093)	0.27%	\$ (21,136)	\$ (62,378)	
July 2011	\$ (7,849,320)	\$ (23,165,471)	0.27%	\$ (21,193)	\$ (62,547)	
August 2011	\$ (7,849,320)	\$ (23,165,471)	0.28%	\$ (21,978)	\$ (64,863)	
September 2011	\$ (7,849,320)	\$ (23,165,471)	0.27%	\$ (21,193)	\$ (62,547)	
October 2011	\$ (7,913,684)	\$ (23,355,428)	0.28%	\$ (22,158)	\$ (65,395)	
November 2011	\$ (7,913,684)	\$ (23,355,428)	0.27%	\$ (21,367)	\$ (63,060)	
December 2011	\$ (7,913,684)	\$ (23,355,428)	0.28%	\$ (22,158)	\$ (65,395)	
January 2012	\$ (7,979,367)	\$ (23,549,278)	0.28%	\$ (22,342)	\$ (65,938)	
February 2012	\$ (7,979,367)	\$ (23,549,278)	0.26%	\$ (20,746)	\$ (61,228)	
March 2012	\$ (7,979,367)	\$ (23,549,278)	0.28%	\$ (22,342)	\$ (65,938)	
April 2012	\$ (8,044,797)	\$ (23,742,382)	0.27%	\$ (21,721)	\$ (64,104)	
May 2012	\$ (8,044,797)	\$ (23,742,382)	0.28%	\$ (22,525)	\$ (66,479)	
Total Surcharge/(Refund)				\$ (8,089,043)	\$ (23,872,965)	
				Interest	Principal	Total (check)
				Pre-1997	\$ (260,859)	\$ (7,828,184) \$ (8,089,043) \$ -
				Post-1996	\$ (769,872)	\$ (23,103,093) \$ (23,872,965) \$ -
				Total	<u>\$ (1,030,731)</u>	<u>\$ (30,931,277)</u> <u>\$ (31,962,008)</u>

Connecticut Light & Power Company (CL&P)
Investment Return and Income Taxes - 2011
for Rates billed June 1, 2012 - May 31, 2013
Pre-1997

	CAPITALIZATION <u>12/31/2011</u>	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 2,321,030,172	47.91%	5.80%	2.78%	
PREFERRED STOCK	\$ 116,716,166	2.41%	4.81%	0.12%	0.12%
COMMON EQUITY	\$ 2,407,035,776	49.68%	11.64%	5.78%	5.78%
TOTAL INVESTMENT RETURN	<u>\$ 4,844,782,114</u>	<u>100.00%</u>		<u>8.68%</u>	<u>5.90%</u>

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0868

(b) Federal Income Tax =
$$\left(\text{R.O.E.} + \frac{\text{PTF Inv. (Tax Credit)} + \frac{\text{Eq. AFUDC of Deprec. Exp.}}{(1 - \text{Federal Income Tax Rate})}}{\text{PTF Inv. Base}} \right) \times \text{Federal Income Tax Rate}$$

=
$$0.0590 + \frac{(84,117) + \frac{315,021}{1 - 0.35}}{286,724,257} \times 0.35$$

= 0.032203

(c) State Income Tax =
$$\left(\text{R.O.E.} + \frac{\text{PTF Inv. (Tax Credit)} + \frac{\text{Eq. AFUDC of Deprec. Exp.}}{(1 - \text{State Income tax Rate})}}{\text{PTF Inv. Base}} + \text{Federal Income Tax} \right) \times \text{State Income Tax Rate}$$

=
$$0.0590 + \frac{(84,117) + \frac{315,021}{1 - 0.0825}}{286,724,257} + 0.032203 \times 0.0825$$

= 0.008273

(a)+(b)+(c) Cost of Capital Rate = 0.127276

	Pre-1997 PTF	
INVESTMENT BASE	\$ 286,724,257	From Worksheet 1, line 13
x Cost of Capital Rate	0.127276	
= Investment Return and Income Taxes	<u>\$ 36,493,117</u>	To Worksheet 1, line 14

Connecticut Light & Power Company (CL&P)
Investment Return and Income Taxes - 2011
for Rates billed June 1, 2012 - May 31, 2013
Post-1996

	CAPITALIZATION 12/31/2011	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 2,321,030,172	47.91%	5.80%	2.78%	
PREFERRED STOCK	\$ 116,716,166	2.41%	4.81%	0.12%	0.12%
COMMON EQUITY	\$ 2,407,035,776	49.68%	11.64%	5.78%	5.78%
TOTAL INVESTMENT RETURN	<u>\$ 4,844,782,114</u>	<u>100.00%</u>		<u>8.68%</u>	<u>5.90%</u>

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0868

(b) Federal Income Tax =
$$\left(\text{R.O.E.} + \frac{\text{PTF Inv. (Tax Credit)} + \frac{\text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}}}{1 - \text{Federal Income Tax Rate}} \right) \times \text{Federal Income Tax Rate}$$

=
$$\left(0.0590 + \frac{(431,113) + \frac{1,614,523}{1 - 0.35}}{1 - 0.35} \right) \times 0.35$$

= 0.032168

(c) State Income Tax =
$$\left(\text{R.O.E.} + \frac{\text{PTF Inv. (Tax Credit)} + \frac{\text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}}}{1 - \text{State Income Tax Rate}} \right) + \text{Federal Income Tax} \times \text{State Income Tax Rate}$$

=
$$\left(0.0590 + \frac{(431,113) + \frac{1,614,523}{1 - 0.0825}}{1 - 0.0825} \right) + 0.032168 \times 0.0825$$

= 0.008264

(a)+(b)+(c) Cost of Capital Rate = 0.127232

	Post - 1996 Total PTF	-	Post - 1996 PTF CWIP	=	Post -1996 PTF Excluding CWIP	
INVESTMENT BASE	\$ 1,598,125,917		\$ 128,817,356		\$ 1,469,308,561	From Worksheet 1, line 13
x Cost of Capital Rate	0.127232		0.127232		0.127232	
= Investment Return and Income Taxes	<u>\$ 203,332,757</u>		<u>\$ 16,389,690</u>		<u>\$ 186,943,067</u>	To Worksheet 1, line 14

Connecticut Light & Power Company (CL&P)
Investment Return and Income Taxes - 2011
for Rates billed June 1, 2012 - May 31, 2013
Post-2003

	<u>CAPITALIZATION</u> <u>12/31/2011</u>	<u>CAPITALIZATION</u> <u>RATIOS</u>	<u>COST OF</u> <u>CAPITAL</u>	<u>WEIGHTED</u> <u>COST OF</u> <u>CAPITAL</u>	<u>EQUITY</u> <u>PORTION</u>
LONG-TERM DEBT	\$ 2,321,030,172	47.91%	#N/A		
PREFERRED STOCK	116,716,166	2.41%			
COMMON EQUITY	<u>2,407,035,776</u>	<u>49.68%</u>	1.00%	<u>0.50%</u>	<u>0.50%</u>
TOTAL INVESTMENT RETURN	\$ <u>4,844,782,114</u>	<u>100.00%</u>		<u>0.50%</u>	<u>0.50%</u>

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0050

(b) Federal Income Tax =
$$\frac{\text{R.O.E.} + \left(\left(\frac{\text{PTF Inv. Tax Credit} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) \times \text{Federal Income Tax Rate} \right)}{(1 - \text{Federal Income Tax Rate})}$$

=
$$\frac{0.0050 + \left(\left(\frac{0 + 0}{1,308,113,191} \right) \times 0.35 \right)}{(1 - 0.35)}$$

= 0.002692

(c) State Income Tax =
$$\frac{\text{R.O.E.} + \left(\left(\frac{\text{PTF Inv. Tax Credit} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) \times \text{Federal Income Tax} \right) + \text{Federal Income Tax}}{(1 - \text{State Income Tax Rate})} \times \text{State Income Tax Rate}$$

=
$$\frac{0.0050 + \left(\left(\frac{0 + 0}{1,308,113,191} \right) \times 0.002692 \right) + 0.002692}{(1 - 0.0825)} \times 0.0825$$

= 0.000692

(a)+(b)+(c) Cost of Capital Rate = 0.008384

Post - 2003 PTF

INVESTMENT BASE	\$ 1,308,113,191	From Worksheet 1 Line 4
x Cost of Capital Rate	0.008384	
= Investment Return and Income Taxes	<u>10,967,221</u>	To Worksheet 1a Line 5

Connecticut Light & Power Company (CL&P)
Investment Return and Income Taxes - 2011
for Rates billed June 1, 2012 - May 31, 2013
M-N Advanced Technology

	CAPITALIZATION 12/31/2011	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 2,321,030,172	47.91%	#N/A		
PREFERRED STOCK	\$ 116,716,166	2.41%			
COMMON EQUITY	\$ 2,407,035,776	49.68%	0.46%	0.23%	0.23%
TOTAL INVESTMENT RETURN	\$ 4,844,782,114	100.00%		0.23%	0.23%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0023

$$(b) \text{ Federal Income Tax} = \frac{\text{R.O.E.} + \left(\left(\frac{\text{PTF Inv. Tax Credit} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) \times \text{Federal Income Tax Rate} \right)}{(1 - \text{Federal Income Tax Rate})}$$

$$= \frac{0.0023 + \left(\left(\frac{0 + 0}{377,922,757} \right) \times 0.35 \right)}{(1 - 0.35)}$$

= 0.001238

$$(c) \text{ State Income Tax} = \frac{\text{R.O.E.} + \left(\left(\frac{\text{PTF Inv. Tax Credit} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) + \text{Federal Income Tax} \right) \times \text{State Income Tax Rate}}{(1 - \text{State Income Tax Rate})}$$

$$= \frac{0.0023 + \left(\left(\frac{0 + 0}{377,922,757} \right) + 0.001238 \right) \times 0.0825}{(1 - 0.0825)}$$

= 0.000318

(a)+(b)+(c) Cost of Capital Rate = 0.003856

M-N Adv Tech PTF

INVESTMENT BASE	\$ 377,922,757	From Worksheet 1 Line 4
x Cost of Capital Rate	0.003856	
= Investment Return and Income Taxes	<u>\$ 1,457,270</u>	To Worksheet 1a Line 5

Connecticut Light & Power Company (CL&P)
Investment Return and Income Taxes - 2011
for Rates billed June 1, 2012 - May 31, 2013
NEEWS

	CAPITALIZATION 12/31/2011	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 2,321,030,172	47.91%	#N/A		
PREFERRED STOCK	\$ 116,716,166	2.41%			
COMMON EQUITY	\$ 2,407,035,776	49.68%	1.25%	0.62%	0.62%
TOTAL INVESTMENT RETURN	<u>\$ 4,844,782,114</u>	<u>100.00%</u>		<u>0.62%</u>	<u>0.62%</u>

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0062

$$(b) \text{ Federal Income Tax} = \frac{\text{R.O.E.} + \left(\left(\frac{\text{PTF Inv. Tax Credit} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) \times \text{Federal Income Tax Rate} \right)}{(1 - \text{Federal Income Tax Rate})}$$

$$= \frac{0.0062 + \left(\left(\frac{0 + 0}{138,082,824} \right) \times 0.35 \right)}{(1 - 0.35)}$$

$$= \underline{\underline{0.003338}}$$

$$(c) \text{ State Income Tax} = \frac{\text{R.O.E.} + \left(\left(\frac{\text{PTF Inv. Tax Credit} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) \times \text{Federal Income Tax} \right) + \text{State Income Tax Rate}}{(1 - \text{State Income Tax Rate})}$$

$$= \frac{0.0062 + \left(\left(\frac{0 + 0}{138,082,824} \right) \times 0.003338 \right) + 0.0825}{(1 - 0.0825)}$$

$$= \underline{\underline{0.000858}}$$

(a)+(b)+(c) Cost of Capital Rate = 0.0103960

	Total NEEWS	NEEWS CWIP	NEEWS Excluding CWIP	
INVESTMENT BASE	\$ 138,082,824	\$ 128,817,356	\$ 9,265,468	From Worksheet 1 Line 4
x Cost of Capital Rate	0.010396	0.010396	0.010396	
= Investment Return and Income Taxes	<u>\$ 1,435,509</u>	<u>\$ 1,339,185</u>	<u>\$ 96,324</u>	To Worksheet 1a Line 5

Connecticut Light & Power Company (CL&P)
Rate Base Items - 2011
for Rates billed June 1, 2012 - May 31, 2013

Line No.		(1) Total	(2) Wage/Plant Allocation Factors (a)	(3) = (1)*(2) Transmission Allocated	Pre-1997 PTF		Post-1996 PTF		Reference
					(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	(6) PTF Allocation Factor (b)	(7) = (3)*(6) PTF Allocated	
	<u>Transmission Plant</u>								
1	Transmission Plant					365,003,371		1,870,692,407	Attachment A
2	General Plant	87,347,012		87,347,012	14.3173%	12,505,734	73.3780%	64,093,490	FF1 page 204 In. 96, footnote
3	Total (line 1+2)	<u>87,347,012</u>		<u>87,347,012</u>		<u>377,509,105</u>		<u>1,934,785,897</u>	
4	<u>Transmission Plant Held for Future Use</u>	1,114,095 (c)		1,114,095	14.3173%	<u>159,508</u>	73.3780%	<u>817,501</u>	(c)
	<u>Transmission Accumulated Depreciation</u>								
5	Transmission Accum. Depreciation	450,061,056		450,061,056	14.3173%	64,436,592	73.3780%	330,245,802	FF1 page 219 In. 25
6	General Plant Accum. Depreciation	<u>11,259,143</u>		<u>11,259,143</u>	14.3173%	<u>1,612,005</u>	73.3780%	<u>8,261,734</u>	FF1 page 219 In. 28, footnote
7	Total (line 5+6)	<u>461,320,199</u>		<u>461,320,199</u>		<u>66,048,597</u>		<u>338,507,536</u>	
	<u>Transmission Accumulated Deferred Taxes</u>								
8	Accumulated Deferred Taxes (281 to 283)	(295,204,712)		(295,204,712)	14.3173%	(42,265,344)	73.3780%	(216,615,314)	FF1 page 274 In. 9 & 276 In. 19, footnote
9	Accumulated Deferred Taxes (190)	<u>51,634,435 (d)</u>		<u>51,634,435</u>	14.3173%	<u>7,392,657</u>	73.3780%	<u>37,888,316</u>	(d)
10	Total (line 8+9)	<u>(243,570,277)</u>		<u>(243,570,277)</u>		<u>(34,872,687)</u>		<u>(178,726,998)</u>	
11	<u>Transmission loss on Reacquired Debt</u>	6,287,787		6,287,787	14.3173%	<u>900,241</u>	73.3780%	<u>4,613,852</u>	FF1 page 110 In. 81, footnote
	<u>Other Regulatory Assets</u>								
12	FAS 106	-		-	14.3173%	-	73.3780%	-	FF1 page 232
13	FAS 109	20,750,469		20,750,469	14.3173%	2,970,907	73.3780%	15,226,279	FF1 page 232 In. 10, footnote
14	Other Regulatory Liabilities (254.DK)	<u>(2,165,603)</u>		<u>(2,165,603)</u>	14.3173%	<u>(310,056)</u>	73.3780%	<u>(1,589,076)</u>	FF1 page 278 In. 5, footnote
15	Total (line 12+13+14)	<u>18,584,866</u>		<u>18,584,866</u>		<u>2,660,851</u>		<u>13,637,203</u>	
16	<u>Transmission Prepayments (165)</u>	3,495,446		3,495,446	14.3173%	<u>500,453</u>	73.3780%	<u>2,564,888</u>	FF1 page 110 In. 57, footnote
17	<u>Transmission Materials and Supplies</u>	31,531,823		31,531,823	14.3173%	<u>4,514,506</u>	73.3780%	<u>23,137,421</u>	FF1 page 227 In. 8
18	<u>Cash Working Capital</u>								
19	Operation & Maintenance Expense					5,227,172		26,789,936	W/S 4A, Line 17
20	Administrative & General Expense					5,678,048		29,100,726	W/S 4A, Line 18
21	Transmission Support Expense					301,795		-	W/S 7
22	Subtotal (line 19+20+21)					<u>11,207,015</u>		<u>55,890,662</u>	
23						0.125		0.125	x 45 / 360
24	Total (line 22 * line 23)					<u>1,400,877</u>		<u>6,986,333</u>	

(a) All B/S items functionalized per FERC Form 1; therefore, no need to use Wage/Plant Allocation Factor (column 2)

(b) W/S 5A & 5B

(c)

Account 105	32,511,067	FF1 page 214 In. 15
Less Third Underground Conduit Duct	<u>31,396,972</u>	
	<u>1,114,095</u>	

(d)

Account 190	68,985,435	FF1 page 234 In. 18, footnote
Less Reserve for Disputed Transactions	<u>17,351,000</u>	FF1 page 234 In. 18, footnote
Total Account 190	<u>51,634,435</u>	

Connecticut Light & Power Company (CL&P)
Expense Items - 2011
for Rates billed June 1, 2012 - May 31, 2013

Line No.		(1) Total	(2) Wage/Plant Allocation Factors (a)	(3) = (1)*(2) Transmission Allocated	PRE-97 PTF		POST-96 PTF		Reference
					(4) PTF Allocation Factor (b)	(5) = (3)*(4) Pre-97 PTF Allocated	(6) PTF Allocation Factor (b)	(7) = (3)*(6) Post-96 PTF Allocated	
	<u>Depreciation Expense</u>								
1	Transmission Depreciation	58,433,481		58,433,481	14.3173%	8,366,097	73.3780%	42,877,320	FF1 page 336 ln. 7
2	General Depreciation	3,503,490		3,503,490	14.3173%	501,605	73.3780%	2,570,791	FF1 page 336 ln. 10, footnote
3	Total (line 1+2)	<u>61,936,971</u>		<u>61,936,971</u>		<u>8,867,702</u>		<u>45,448,111</u>	
4	<u>Amortization of Loss on Reacquired Debt</u>	458,214		458,214	14.3173%	<u>65,604</u>	73.3780%	<u>336,228</u>	FF1 page 114 ln. 64, footnote
5	<u>Amortization of Investment Tax Credits</u>	587,523		587,523	14.3173%	<u>84,117</u>	73.3780%	<u>431,113</u>	FF1 page 266 ln. 8, footnote - difference of PY-CY
	<u>Property Taxes</u>								
6	Transmission Property Taxes	35,874,626		35,874,626	14.3173%	5,136,278	73.3780%	26,324,083	FF1 page 262 ln. 24i, footnote
7	General Property Taxes (c)	-		-	14.3173%	-	73.3780%	-	
8	Total (line 6+7)	<u>35,874,626</u>		<u>35,874,626</u>		<u>5,136,278</u>		<u>26,324,083</u>	
	<u>Transmission Operation and Maintenance</u>								
9	Operation and Maintenance	99,471,858		99,471,858	14.3173%	14,241,684	73.3780%	72,990,460	FF1 page 321 ln. 112
10	Transmission of Electricity by Others - #565	45,818,400		45,818,400	14.3173%	6,559,958	73.3780%	33,620,626	FF1 page 321 ln. 96
11	Load Dispatching - #561	-		-	14.3173%	-	73.3780%	-	FF1 page 321 ln. 84
12	Account 561.1	2,444,613		2,444,613	14.3173%	350,003	73.3780%	1,793,808	FF1 page 321 ln. 85
13	Account 561.2	7,397,148		7,397,148	14.3173%	1,059,072	73.3780%	5,427,879	FF1 page 321 ln. 86
14	Account 561.3	1,459,001		1,459,001	14.3173%	208,890	73.3780%	1,070,586	FF1 page 321 ln. 87
15	Account 561.4	5,843,202		5,843,202	14.3173%	836,589	73.3780%	4,287,625	FF1 page 321 ln. 88
16	**Station Expenses & Rents	-		-	14.3173%	-	73.3780%	-	FF1 page 321 ln. 93 + ln. 98
17	O&M less lines 10 thru 16	<u>36,509,494</u>		<u>36,509,494</u>		<u>5,227,172</u>		<u>26,789,936</u>	
	<u>Transmission Administrative and General</u>								
18	Administrative and General	39,658,653		39,658,653	14.3173%	<u>5,678,048</u>	73.3780%	<u>29,100,726</u>	FF1 page 320 ln. 197 b, footnote
19	<u>Payroll Tax Expense</u>	478,083		478,083	14.3173%	<u>68,449</u>	73.3780%	<u>350,808</u>	
	Federal Unemployment	5,636							FF1 page 262 ln. 2i, footnote
	FICA	347,600							FF1 page 262 ln. 4i, footnote
	Medicare	99,845							FF1 page 262 ln. 8i, footnote
	CT Unemployment	21,680							FF1 page 262 ln. 14i, footnote
	DC Unemployment	16							FF1 page 262.1 ln. 14i, footnote
	FL Unemployment	2							FF1 page 262.1 ln. 18i, footnote
	GA Unemployment	-							FF1 page 262 footnote
	MA Unemployment	51							FF1 page 262 ln. 32i, footnote
	MA Universal Health	10							FF1 page 262 ln. 33i, footnote
	NH Unemployment	3,190							FF1 page 262.1 ln. 4i, footnote
	NJ Unemployment	-							FF1 page 262 footnote
	NY Unemployment	53							FF1 page 262.1 ln. 10i, footnote
	Total	478,083	To Line 19						

** To the extent that PTF Support Payments are reflected in worksheet 7 they will be excluded from this calculation.

(a) All expenses functionalized per FERC Form 1; therefore, no need to use Wage/Plant Allocation Factor (column 2)

(b) W/S 5A & 5B

(c) Transmission related general property taxes are included in the Transmission Property tax number footnoted in the FF1.

Public Service Company of New Hampshire (PSNH)
Investment Return and Income Taxes - 2011
for Rates billed June 1, 2012 - May 31, 2013
Pre-1997

	CAPITALIZATION 12/31/2011	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 989,546,690	47.85%	4.64%	2.22%	
PREFERRED STOCK	\$ -	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	\$ 1,078,362,375	52.15%	11.64%	6.07%	6.07%
TOTAL INVESTMENT RETURN	<u>\$ 2,067,909,065</u>	<u>100.00%</u>		<u>8.29%</u>	<u>6.07%</u>

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0829

(b) Federal Income Tax

$$= \frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) \times \text{Federal Income Tax Rate}}{(1 - \text{Federal Income Tax Rate})}$$

$$= \frac{0.0607 + \left(\frac{(1,718) + 37,626}{71,788,306} \right) \times 0.35}{\left(1 - 0.35 \right)}$$

= 0.032954

(c) State Income Tax

$$= \frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) + \text{Federal Income Tax}}{(1 - \text{State Income Tax Rate})} \times \text{State Income Tax Rate}$$

$$= \frac{0.0607 + \left(\frac{(1,718) + 37,626}{71,788,306} \right) + 0.032954}{\left(1 - 0.085 \right)} \times 0.085$$

= 0.008747

(a)+(b)+(c) Cost of Capital Rate = 0.124601

	<u>Pre-1997 PTF</u>	
INVESTMENT BASE	\$ 71,788,306	From Worksheet 1, line 13
x Cost of Capital Rate	0.124601	
= Investment Return and Income Taxes	<u>\$ 8,944,895</u>	To Worksheet 1, line 14

Public Service Company of New Hampshire (PSNH)
Investment Return and Income Taxes - 2011
for Rates billed June 1, 2012 - May 31, 2013
Post-1996

	CAPITALIZATION 12/31/2011	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 989,546,690	47.85%	4.64%	2.22%	
PREFERRED STOCK	\$ -	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	\$ 1,078,362,375	52.15%	11.64%	6.07%	6.07%
TOTAL INVESTMENT RETURN	<u>\$ 2,067,909,065</u>	<u>100.00%</u>		<u>8.29%</u>	<u>6.07%</u>

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0829

(b) Federal Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / (1 - \text{Federal Income Tax Rate})}{\left(\frac{0.0607 + \left(\frac{(6,923) + 151,584}{1} \right) / - 0.35}{288,912,300} \right) \times 0.35} \right)$$

= 0.032954

(c) State Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / (1 - \text{State Income Tax Rate}) + \text{Federal Income Tax}}{0.085} \right) \times \text{State Income Tax Rate}$$

=
$$\left(\frac{0.0607 + \left(\frac{(6,923) + 151,584}{1} \right) / - 0.085}{288,912,300} + 0.032954 \right) \times 0.085$$

= 0.008747

(a)+(b)+(c) Cost of Capital Rate = 0.124601

Post - 1996 Total PTF

INVESTMENT BASE	\$ 288,912,300	From Worksheet 1, line 13
x Cost of Capital Rate	0.124601	
= Investment Return and Income Taxes	<u>\$ 35,998,761</u>	To Worksheet 1, line 14

Public Service Company of New Hampshire (PSNH)
Investment Return and Income Taxes - 2011
for Rates billed June 1, 2012 - May 31, 2013
Post-2003

	<u>CAPITALIZATION</u> <u>12/31/2011</u>	<u>CAPITALIZATION</u> <u>RATIOS</u>	<u>COST OF</u> <u>CAPITAL</u>	<u>WEIGHTED</u> <u>COST OF</u> <u>CAPITAL</u>	<u>EQUITY</u> <u>PORTION</u>
LONG-TERM DEBT	\$ 989,546,690	47.85%	#N/A		
PREFERRED STOCK	\$ -	0.00%			
COMMON EQUITY	\$ 1,078,362,375	52.15%	1.00%	0.52%	0.52%
TOTAL INVESTMENT RETURN	<u>\$ 2,067,909,065</u>	<u>100.00%</u>		<u>0.52%</u>	<u>0.52%</u>

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0052

(b) Federal Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. Tax Credit} + \frac{\text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right)}{1 - \text{Federal Income Tax Rate}} \right) \times \text{Federal Income Tax Rate}$$

=
$$\left(\frac{0.0052 + \left(\frac{0 + \frac{0}{101,001,150}}{1 - 0.35} \right)}{1 - 0.35} \right) \times 0.35$$

= 0.002800

(c) State Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. Tax Credit} + \frac{\text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right)}{1 - \text{State Income Tax Rate}} + \text{Federal Income Tax} \right) \times \text{State Income Tax Rate}$$

=
$$\left(\frac{0.0052 + \left(\frac{0 + \frac{0}{101,001,150}}{1 - 0.085} \right) + 0.002800}{1 - 0.085} \right) \times 0.085$$

= 0.000743

(a)+(b)+(c) Cost of Capital Rate = 0.008743

Post - 2003 PTF

INVESTMENT BASE \$ 101,001,150 From Worksheet 1 Line 4

x Cost of Capital Rate 0.008743

= Investment Return and Income Taxes \$ 883,053 To Worksheet 1a Line 5

Public Service Company of New Hampshire (PSNH)
Rate Base Items - 2011
for Rates billed June 1, 2012 - May 31, 2013

Worksheet 3B

Line No.		(1) Total	(2) Wage/Plant Allocation Factors (a)	(3) = (1)*(2) Transmission Allocated	Pre-1997 PTF		Post-1996 PTF		Reference
					(4) PTF Allocation Factor (b)	(5) = (3)*(4) Pre-97 PTF Allocated	(6) PTF Allocation Factor (b)	(7) = (3)*(6) Post-96 PTF Allocated	
1	Transmission Plant					90,490,711		364,557,343	Attachment A1
2	General Plant	40,705,818		40,705,818	18.3978%	7,488,975	74.1188%	30,170,664	FF1 page 204 In. 104, footnote
3	Total (line 1+2)	40,705,818		40,705,818		97,979,686		394,728,007	
4	<u>Transmission Plant Held for Future Use</u>	9,395,359		9,395,359	18.3978%	1,728,539	74.1188%	6,963,727	FF1 page 214 In. 34
	<u>Transmission Accumulated Depreciation</u>								
5	Transmission Accum. Depreciation	97,530,384		97,530,384	18.3978%	17,943,445	74.1188%	72,288,350	FF1 page 219 In. 25
6	General Plant Accum. Depreciation	8,774,596		8,774,596	18.3978%	1,614,333	74.1188%	6,503,625	FF1 page 219 In. 28, footnote
7	Total (line 5+6)	106,304,980		106,304,980		19,557,778		78,791,975	
	<u>Transmission Accumulated Deferred Taxes</u>								
8	Accumulated Deferred Taxes (281-283)	(88,856,533)		(88,856,533)	18.3978%	(16,347,647)	74.1188%	(65,859,396)	FF1 page 274 In. 9 & 276 In. 19, footnote
9	Accumulated Deferred Taxes (190)	11,301,708 (c)		11,301,708	18.3978%	2,079,266	74.1188%	8,376,690	(c)
10	Total (line 8+9)	(77,554,825)		(77,554,825)		(14,268,381)		(57,482,706)	
11	<u>Transmission loss on Reacquired Debt</u>	1,896,258		1,896,258	18.3978%	348,870	74.1188%	1,405,484	FF1 page 110 In. 81, footnote
	<u>Other Regulatory Assets</u>								
12	FAS 106	-		-	18.3978%	-	74.1188%	-	FF1 page 232
13	FAS 109	7,479,462		7,479,462	18.3978%	1,376,056	74.1188%	5,543,687	FF1 page 232 In. 1, footnote
14	Other Regulatory Liabilities (254.DK)	(20,950)		(20,950)	18.3978%	(3,854)	74.1188%	(15,528)	FF1 page 278 In. 1, footnote
15	Total (line 12+13+14)	7,458,512		7,458,512		1,372,202		5,528,159	
16	<u>Transmission Prepayments</u>	5,111,595		5,111,595	18.3978%	940,421	74.1188%	3,788,653	FF1 page 110 In. 57, footnote
17	<u>Transmission Materials and Supplies</u>	14,793,205		14,793,205	18.3978%	2,721,624	74.1188%	10,964,546	FF1 page 227 In. 8
18	<u>Cash Working Capital</u>								
19	Operation & Maintenance Expense					1,947,301		7,845,050	W/S 4B, Line 17
20	Administrative & General Expense					1,643,762		6,622,188	W/S 4B, Line 18
21	Transmission Support Expense					593,924		-	W/S 7
22	Subtotal (line 19+20+21)					4,184,987		14,467,238	
23						0.125		0.125	x 45 / 360
24	Total (line 22 * line 23)					523,123		1,808,405	

(a) All B/S items functionalized per FERC Form 1; therefore, no need to use Wage/Plant Allocation Factor (column 2)

(b) W/S 5A & 5B

(c)

Account 190	11,301,708	FF1 page 234 In. 18, footnote
Less Reserve for Disputed Transactions	-	FF1 page 234 In. 18, footnote
Total Account 190	11,301,708	

Public Service Company of New Hampshire (PSNH)
Expense Items - 2011
for Rates billed June 1, 2012 - May 31, 2013

Worksheet 4B

Line No.		(1)	(2)	(3) = (1)*(2)	Pre-1997 PTF		Post-1996 PTF		Reference
			Wage/Plant		(4)	(5) = (3)*(4)	(6)	(7) = (3)*(6)	
		Total	Allocation Factors (a)	Transmission Allocated	Allocation Factor (b)	Pre-97 PTF Allocated	Allocation Factor (b)	Post-96 PTF Allocated	
	<u>Depreciation Expense</u>								
1	Transmission Depreciation	8,894,953		8,894,953	18.3978%	1,636,476	74.1188%	6,592,832	FF 1 page 336 ln. 7
2	General Depreciation	2,085,638		2,085,638	18.3978%	383,712	74.1188%	1,545,850	FF1 page 336 ln. 10, footnote
3	Total (line 1+2)	<u>10,980,591</u>		<u>10,980,591</u>		<u>2,020,188</u>		<u>8,138,682</u>	
4	<u>Amortization of Loss on Reacquired Debt</u>	190,805		190,805	18.3978%	<u>35,104</u>	74.1188%	<u>141,422</u>	FF1 page 114 ln. 64, footnote
5	<u>Amortization of Investment Tax Credits</u>	9,340		9,340	18.3978%	<u>1,718</u>	74.1188%	<u>6,923</u>	FF1 page 266 ln. 8, footnote - (difference between py & cy)
	<u>Property Taxes</u>								
6	Transmission Property Taxes	11,573,201		11,573,201	18.3978%	2,129,214	74.1188%	8,577,918	FF1 page 262 ln. 23i + ln. 31i + page 262.1 ln. 2i, footnote
7	General Property Taxes (c)	-		-	18.3978%	-	74.1188%	-	
8	Total (line 6+7)	<u>11,573,201</u>		<u>11,573,201</u>		<u>2,129,214</u>		<u>8,577,918</u>	
	<u>Transmission Operation and Maintenance</u>								
9	Operation and Maintenance	27,013,218		27,013,218	18.3978%	4,969,838	74.1188%	20,021,873	FF1 page 321 ln. 112
10	Transmission of Electricity by Others - #565	13,210,354		13,210,354	18.3978%	2,430,415	74.1188%	9,791,356	FF1 page 321 ln. 96
11	Load Dispatching - #561	53		53	18.3978%	10	74.1188%	39	FF1 page 321 ln. 84
12	Account 561.1	626,196		626,196	18.3978%	115,206	74.1188%	464,129	FF1 page 321 ln. 85
13	Account 561.2	624,393		624,393	18.3978%	114,875	74.1188%	462,793	FF1 page 321 ln. 86
14	Account 561.3	17,138		17,138	18.3978%	3,153	74.1188%	12,702	FF1 page 321 ln. 87
15	Account 561.4	1,950,658		1,950,658	18.3978%	358,878	74.1188%	1,445,804	FF1 page 321 ln. 88
16	**Station Expenses & Rents	-		-	18.3978%	-	74.1188%	-	FF1 page 321 ln. 93 + ln. 98
17	O&M less lines 10 thru 16	<u>10,584,426</u>		<u>10,584,426</u>		<u>1,947,301</u>		<u>7,845,050</u>	
	<u>Transmission Administrative and General</u>								
18	Administrative and General	8,934,559		8,934,559	18.3978%	<u>1,643,762</u>	74.1188%	<u>6,622,188</u>	FF1 page 320 ln. 197 b, footnote
19	<u>Payroll Tax Expense</u>	123,749		<u>123,749</u>	18.3978%	<u>22,767</u>	74.1188%	<u>91,721</u>	
	Federal Unemployment	1,381							FF1 page 262 ln. 3i, footnote
	FICA	91,730							FF1 page 262 ln. 5i, footnote
	Medicare	25,436							FF1 page 262 ln. 8i, footnote
	CT Unemployment	3,634							FF1 page 262.1 ln. 7i, footnote
	DC Unemployment	4							FF1 page 262 ln. 27i, footnote
	FL Unemployment	-							FF1 page 262.1 ln. 27i, footnote
	GA Unemployment	-							FF1 page 262, footnote
	MA Unemployment	11							FF1 page 262.1 ln. 15i, footnote
	MA Universal Health	2							FF1 page 262.1 ln. 16i, footnote
	NH Unemployment	1,539							FF1 page 262 ln. 15i, footnote
	NJ Unemployment	-							FF1 page 262, footnote
	NY Unemployment	12							FF1 page 262.1 ln. 22i, footnote
	Total	<u>123,749</u>	To Line 19						

** To the extent that PTF Support Payments are reflected in worksheet 7 they will be excluded from this calculation.

(a) All expenses functionalized per FERC Form 1; therefore, no need to use Wage/Plant Allocation Factor (column 2)

(b) W/S 5A & 5B

(c) Transmission related general property taxes are included in the Transmission Property tax number footnoted in the FF1.

Western Massachusetts Electric Company (WMECO)
Investment Return and Income Taxes - 2011
for Rates billed June 1, 2012 - May 31, 2013
Pre-1997

	CAPITALIZATION 12/31/2011	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 439,020,109	48.71%	5.24%	2.55%	
PREFERRED STOCK	\$ -	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	\$ 462,300,518	51.29%	11.64%	5.97%	5.97%
TOTAL INVESTMENT RETURN	<u>\$ 901,320,627</u>	<u>100.00%</u>		<u>8.52%</u>	<u>5.97%</u>

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0852

(b) Federal Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / (1 - \text{Federal Income Tax Rate})}{\frac{0.0597 + ((11,379) + 13,638)}{1 - 0.35}} \right) \times 0.35$$

= 0.032169

(c) State Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / (1 - \text{State Income Tax Rate})}{\frac{0.0597 + ((11,379) + 13,638)}{1 - 0.065}} + 0.032169 \right) \times 0.065$$

= 0.006390

(a)+(b)+(c) Cost of Capital Rate = 0.123759

	<u>Pre-1997 PTF</u>	
INVESTMENT BASE	\$ 53,045,615	From Worksheet 1, line 13
x Cost of Capital Rate	0.123759	
= Investment Return and Income Taxes	<u>\$ 6,564,872</u>	To Worksheet 1, line 14

Western Massachusetts Electric Company (WMECO)
Investment Return and Income Taxes - 2011
for Rates billed June 1, 2012 - May 31, 2013
Post-1996

	CAPITALIZATION 12/31/2011	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 439,020,109	48.71%	5.24%	2.55%	
PREFERRED STOCK	\$ -	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	\$ 462,300,518	51.29%	11.64%	5.97%	5.97%
TOTAL INVESTMENT RETURN	\$ 901,320,627	100.00%		8.52%	5.97%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0852

(b) Federal Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)}}{\text{Eq. AFUDC of Deprec. Exp.}} \right) / \text{PTF Inv. Base}}{(1 - \text{Federal Income Tax Rate})} \times \text{Federal Income Tax Rate} \right)$$

=
$$\left(\frac{0.0597 + \left(\frac{(28,450)}{34,097} \right) / 396,856,362}{(1 - 0.35)} \times 0.35 \right)$$

= 0.032154

(c) State Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)}}{\text{Eq. AFUDC of Deprec. Exp.}} \right) / \text{PTF Inv. Base}}{(1 - \text{State Income Tax Rate})} + \text{Federal Income Tax} \right) \times \text{State Income Tax Rate}$$

=
$$\left(\frac{0.0597 + \left(\frac{(28,450)}{34,097} \right) / 396,856,362}{(1 - 0.065)} + 0.032154 \right) \times 0.065$$

= 0.006387

(a)+(b)+(c) Cost of Capital Rate = 0.123741

	Post - 1996 Total PTF	-	Post - 1996 PTF CWIP	=	Post -1996 PTF Excluding CWIP	
INVESTMENT BASE	\$ 396,856,362		\$ 264,352,233		\$ 132,504,129	From Worksheet 1, line 13
x Cost of Capital Rate	0.1237410		0.1237410		0.1237410	
= Investment Return and Income Taxes	<u>\$ 49,107,403</u>		<u>\$ 32,711,210</u>		<u>\$ 16,396,193</u>	To Worksheet 1, line 14

Western Massachusetts Electric Company (WMECO)
Investment Return and Income Taxes - 2011
for Rates billed June 1, 2012 - May 31, 2013
Post-2003

	<u>CAPITALIZATION</u> <u>12/31/2011</u>	<u>CAPITALIZATION</u> <u>RATIOS</u>	<u>COST OF</u> <u>CAPITAL</u>	<u>WEIGHTED</u> <u>COST OF</u> <u>CAPITAL</u>	<u>EQUITY</u> <u>PORTION</u>
LONG-TERM DEBT	\$ 439,020,109	48.71%	#N/A		
PREFERRED STOCK	\$ -	0.00%			
COMMON EQUITY	\$ 462,300,518	51.29%	1.00%	0.51%	0.51%
TOTAL INVESTMENT RETURN	<u>\$ 901,320,627</u>	<u>100.00%</u>		<u>0.51%</u>	<u>0.51%</u>

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0051

$$\begin{aligned}
 \text{(b) Federal Income Tax} &= \left(\frac{\text{R.O.E.} + \left(\left(\frac{\text{PTF Inv. Tax Credit} + \frac{\text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) \times \text{Federal Income Tax Rate} \right)}{1 - \text{Federal Income Tax Rate}} \right) \\
 &= \left(\frac{0.0051 + \left(\left(\frac{0 + \frac{0}{9,108,971}}{1 - 0.35} \right) \times 0.35 \right)}{1 - 0.35} \right) \\
 &= \underline{\underline{0.002746}}
 \end{aligned}$$

$$\begin{aligned}
 \text{(c) State Income Tax} &= \left(\frac{\text{R.O.E.} + \left(\left(\frac{\text{PTF Inv. Tax Credit} + \frac{\text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) + \text{Federal Income Tax} \right) \times \text{State Income Tax Rate}}{1 - \text{State Income Tax Rate}} \right) \\
 &= \left(\frac{0.0051 + \left(\left(\frac{0 + \frac{0}{9,108,971}}{1 - 0.065} \right) + 0.002746 \right) \times 0.065}{1 - 0.065} \right) \\
 &= \underline{\underline{0.000545}}
 \end{aligned}$$

(a)+(b)+(c) Cost of Capital Rate = 0.008391

Post - 2003 PTF

INVESTMENT BASE	\$ 9,108,971	From Worksheet 1 Line 4
x Cost of Capital Rate	0.008391	
= Investment Return and Income Taxes	<u>\$ 76,433</u>	To Worksheet 1a Line 5

Western Massachusetts Electric Company (WMECO)
Investment Return and Income Taxes - 2011
for Rates billed June 1, 2012 - May 31, 2013
NEEWS

	<u>CAPITALIZATION 12/31/2011</u>	<u>CAPITALIZATION RATIOS</u>	<u>COST OF CAPITAL</u>	<u>WEIGHTED COST OF CAPITAL</u>	<u>EQUITY PORTION</u>
LONG-TERM DEBT	\$ 439,020,109	48.71%	#N/A		
PREFERRED STOCK	\$ -	0.00%			
COMMON EQUITY	\$ 462,300,518	51.29%	1.25%	0.64%	0.64%
TOTAL INVESTMENT RETURN	\$ 901,320,627	100.00%		0.64%	0.64%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0064

$$(b) \text{ Federal Income Tax} = \left(\frac{\text{R.O.E.} + \left(\left(\frac{\text{PTF Inv. Tax Credit} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / \text{PTF Inv. Base} \right)}{(1 - \text{Federal Income Tax Rate})} \times \text{Federal Income Tax Rate} \right)$$

$$= \left(\frac{0.0064 + \left(\left(\frac{0 + 0}{20,686,447} \right) / 1 \right)}{(1 - 0.35)} \times 0.35 \right)$$

= 0.003446

$$(c) \text{ State Income Tax} = \left(\frac{\text{R.O.E.} + \left(\left(\frac{\text{PTF Inv. Tax Credit} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / \text{PTF Inv. Base} \right) + \text{Federal Income Tax}}{(1 - \text{State Income Tax Rate})} \times \text{State Income Tax Rate} \right)$$

$$= \left(\frac{0.0064 + \left(\left(\frac{0 + 0}{20,686,447} \right) / 1 \right) + 0.003446}{(1 - 0.065)} \times 0.065 \right)$$

= 0.000684

(a)+(b)+(c) Cost of Capital Rate = 0.010530

	<u>Total NEEWS</u>	<u>NEEWS CWIP</u>	<u>NEEWS Excluding CWIP</u>	
INVESTMENT BASE	\$ 285,038,680	\$ 264,352,233	\$ 20,686,447	From Worksheet 1 Line 4
x Cost of Capital Rate	0.010530	0.010530	0.010530	
= Investment Return and Income Taxes	<u>\$ 3,001,457</u>	<u>\$ 2,783,629</u>	<u>\$ 217,828</u>	To Worksheet 1a Line 5

Western Massachusetts Electric Company (WMECO)
Rate Base Items - 2011
for Rates billed June 1, 2012 - May 31, 2013

Worksheet 3C

Line No.		(1) Total	(2) Wage/Plant Allocation Factors (a)	(3) = (1)*(2) Transmission Allocated	Pre-1997 PTF		Post-1996 PTF		Reference
					(4) PTF Allocation Factor (b)	(5) = (3)*(4) Pre-97 PTF Allocated	(6) PTF Allocation Factor (b)	(7) = (3)*(6) Post-96 PTF Allocated	
	<u>Transmission Plant</u>								
1	Transmission Plant					60,534,512		151,347,756	Attachment A2
2	General Plant	13,966,462		13,966,462	24.9548%	3,485,303	62.3918%	8,713,927	FF1 page 204 ln. 96, footnote
3	Total (line 1+2)	<u>13,966,462</u>		<u>13,966,462</u>		<u>64,019,815</u>		<u>160,061,683</u>	
4	<u>Transmission Plant Held for Future Use</u>	38,361,934		38,361,934	24.9548%	<u>9,573,144</u>	62.3918%	<u>23,934,701</u>	FF1 page 214 ln. 16
	<u>Transmission Accumulated Depreciation</u>								
5	Transmission Accum. Depreciation	46,818,653		46,818,653	24.9548%	11,683,501	62.3918%	29,211,000	FF1 page 219 ln. 25
6	General Plant Accum. Depreciation	<u>1,862,996</u>		<u>1,862,996</u>	24.9548%	<u>464,907</u>	62.3918%	<u>1,162,357</u>	FF1 page 219 ln. 28, footnote
7	Total (line 5+6)	<u>48,681,649</u>		<u>48,681,649</u>		<u>12,148,408</u>		<u>30,373,357</u>	
	<u>Transmission Accumulated Deferred Taxes</u>								
8	Accumulated Deferred Taxes (281-283)	(45,172,466)		(45,172,466)	24.9548%	(11,272,699)	62.3918%	(28,183,915)	FF1 page 274 ln. 9 & 276 ln. 19, footnote
9	Accumulated Deferred Taxes (190)	8,038,308 (c)		8,038,308	24.9548%	2,005,944	62.3918%	5,015,245	(c)
10	Total (line 8+9)	<u>(37,134,158)</u>		<u>(37,134,158)</u>		<u>(9,266,755)</u>		<u>(23,168,670)</u>	
11	<u>Transmission loss on Reacquired Debt</u>	70,412		70,412	24.9548%	<u>17,571</u>	62.3918%	<u>43,931</u>	FF1 page 110 ln. 81, footnote
	<u>Other Regulatory Assets</u>								
12	FAS 106	-		-	24.9548%	-	62.3918%	-	FF1 page 232
13	FAS 109	901,556		901,556	24.9548%	224,981	62.3918%	562,497	FF1 page 232 ln. 7, footnote
14	Other Regulatory Liabilities (254.DK)	<u>(137,915)</u>		<u>(137,915)</u>	24.9548%	<u>(34,416)</u>	62.3918%	<u>(86,048)</u>	FF1 page 278 ln. 5, footnote
15	Total (line 12+13+14)	<u>763,641</u>		<u>763,641</u>		<u>190,565</u>		<u>476,449</u>	
16	<u>Transmission Prepayments</u>	268,413		268,413	24.9548%	<u>66,982</u>	62.3918%	<u>167,468</u>	FF1 page 110 ln. 57, footnote
17	<u>Transmission Materials and Supplies</u>	931,076		931,076	24.9548%	<u>232,348</u>	62.3918%	<u>580,915</u>	FF1 page 227 ln. 8
18	<u>Cash Working Capital</u>								
19	Operation & Maintenance Expense					1,187,508		2,968,998	W/S 4C, Line 17
20	Administrative & General Expense					1,311,528		3,279,073	W/S 4C, Line 18
21	Transmission Support Expense					383,786			W/S 7
22	Subtotal (line 19+20+21)					<u>2,882,822</u>		<u>6,248,071</u>	
23						0.125		0.125	x 45 / 360
24	Total (line 22 * line 23)					<u>360,353</u>		<u>781,009</u>	

(a) All B/S items functionalized per FERC Form 1; therefore, no need to use Wage/Plant Allocation Factor (column 2)

(b) W/S 5A & 5B

(c)

Account 190	8,038,308	FF1 page 234 ln. 18, footnote
Less Reserve for Disputed Transactions	-	FF1 page 234 ln. 18, footnote
Total Account 190	<u>8,038,308</u>	

Western Massachusetts Electric Company (WMECO)
Expense Items - 2011
for Rates billed June 1, 2012 - May 31, 2013

Worksheet 4C

Line No.		(1) Total	(2) Wage/Plant Allocation Factors (a)	(3) = (1)*(2) Transmission Allocated	Pre-1997 PTF		Post-1996 PTF		Reference
					(4) PTF Allocation Factor (b)	(5) = (3)*(4) Pre-97 PTF Allocated	(6) PTF Allocation Factor (b)	(7) = (3)*(6) Post-96 PTF Allocated	
	<u>Depreciation Expense</u>								
1	Transmission Depreciation	4,084,197		4,084,197	24.9548%	1,019,203	62.3918%	2,548,204	FF1 page 336 ln. 7
2	General Depreciation	354,925		354,925	24.9548%	88,571	62.3918%	221,444	FF1 page 336 ln. 10, footnote
3	Total (line 1+2)	<u>4,439,122</u>		<u>4,439,122</u>		<u>1,107,774</u>		<u>2,769,648</u>	
4	<u>Amortization of Loss on Reacquired Debt</u>	10,958		10,958	24.9548%	<u>2,735</u>	62.3918%	<u>6,837</u>	FF1 page 114, ln. 64, footnote
5	<u>Amortization of Investment Tax Credits</u>	45,599		45,599	24.9548%	<u>11,379</u>	62.3918%	<u>28,450</u>	FF1 page 266 ln. 8, footnote - difference of PY-CY
	<u>Property Taxes</u>								
6	Transmission Property Taxes	3,537,965		3,537,965	24.9548%	882,892	62.3918%	2,207,400	FF1 page 262 ln. 33i, footnote
7	General Property Taxes (c)			-	24.9548%	-	62.3918%	-	
8	Total (line 6+7)	<u>3,537,965</u>		<u>3,537,965</u>		<u>882,892</u>		<u>2,207,400</u>	
	<u>Transmission Operation and Maintenance</u>								
9	Operation and Maintenance	20,648,095		20,648,095	24.9548%	5,152,691	62.3918%	12,882,718	FF1 page 321 ln. 112
10	Transmission of Electricity by Others - #565	14,941,113		14,941,113	24.9548%	3,728,525	62.3918%	9,322,029	FF1 page 321 ln. 96
11	Load Dispatching - #561	-		-	24.9548%	-	62.3918%	-	FF1 page 321 ln. 84
12	Account 561.1	1,837		1,837	24.9548%	458	62.3918%	1,146	FF1 page 321 ln. 87
13	Account 561.2	22,568		22,568	24.9548%	5,632	62.3918%	14,081	FF1 page 321 ln. 86
14	Account 561.3	1,784		1,784	24.9548%	445	62.3918%	1,113	FF1 page 321 ln. 87
15	Account 561.4	922,158		922,158	24.9548%	230,123	62.3918%	575,351	FF1 page 321 ln. 88
16	**Station Expenses & Rents	-		-	24.9548%	-	62.3918%	-	FF1 page 321 ln. 93 + ln. 98
17	O&M less lines 10 thru 16	<u>4,758,635</u>		<u>4,758,635</u>		<u>1,187,508</u>		<u>2,968,998</u>	
	<u>Transmission Administrative and General</u>								
18	Administrative and General	5,255,616		<u>5,255,616</u>	24.9548%	<u>1,311,528</u>	62.3918%	<u>3,279,073</u>	FF1 page 320 ln. 197, footnote
19	<u>Payroll Tax Expense</u>	55,599		<u>55,599</u>	24.9548%	<u>13,875</u>	62.3918%	<u>34,689</u>	
	Federal Unemployment	654							FF1 page 262 ln. 3i, footnote
	FICA	40,331							FF1 page 262 ln. 4i, footnote
	Medicare	11,669							FF1 page 262 ln. 8i, footnote
	CT Unemployment	1,994							FF1 page 262 ln. 13i, footnote
	DC Unemployment	-							FF1 page 262.1 ln. 8i, footnote
	FL Unemployment	-							FF1 page 262.1 ln. 13i, footnote
	GA Unemployment	-							FF1 page 262, footnote
	MA Unemployment	488							FF1 page 262 ln. 23i, footnote
	MA Universal Health	67							FF1 page 262 ln. 28i, footnote
	NH Unemployment	389							FF1 page 262 ln. 38i, footnote
	NJ Unemployment	-							FF1 page 262 footnote
	NY Unemployment	7							FF1 page 262.1 ln. 3i, footnote
	Total	<u>55,599</u>	To Line 19						

** To the extent that PTF Support Payments are reflected in worksheet 7 they will be excluded from this calculation.

(a) All expenses functionalized per FERC Form 1; therefore, no need to use Wage/Plant Allocation Factor (column 2)

(b) W/S 5A & 5B

(c) Transmission related general property taxes are included in the Transmission Property tax number footnoted in the FF1.

Northeast Utilities System Companies'
Allocation Factors - 2011
for Rates billed June 1, 2012 - May 31, 2013
Pre-1997

Line
No.

	<u>PTF Transmission Plant Allocation Factor</u>	<u>CL&P</u>	<u>PSNH</u>	<u>WMECO</u>	<u>TOTAL</u>	<u>Reference</u>
1	PTF Transmission Investment	365,003,371	90,490,711	60,534,512	516,028,594	W/S 3A,3B,3C line 1
2	Total Transmission Investment	<u>2,549,391,725</u>	<u>491,855,190</u>	<u>242,576,350</u>	<u>3,283,823,265</u>	FF1 page 206-207 ln 58
3	Percent Allocation (Line 1/ Line 2)	<u>14.3173%</u>	<u>18.3978%</u>	<u>24.9548%</u>	<u>15.7143%</u>	
	<u>Plant Allocation Factor</u>					
4	Total Transmission Investment (Line 2)	2,549,391,725	491,855,190	242,576,350	3,283,823,265	
5	<i>plus Transmission-Related General Plant (Line 2 of Wkst. 3)</i>	<u>87,347,012</u>	<u>40,705,818</u>	<u>13,966,462</u>	<u>142,019,292</u>	W/S 3A,3B,3C line 2
6	<i>= Revised Numerator (Line 4 + Line 5)</i>	<u>2,636,738,737</u>	<u>532,561,008</u>	<u>256,542,812</u>	<u>3,425,842,557</u>	
7	Total Plant in Service	7,056,421,479	3,054,013,243	981,963,729	11,092,398,451	FF1 206-207 ln 100
8	Percent Allocation (Line 6 / Line 7)	<u>37.3665%</u>	<u>17.4381%</u>	<u>26.1255%</u>	<u>30.8846%</u>	

Northeast Utilities System Companies'
Allocation Factors - 2011
for Rates billed June 1, 2012 - May 31, 2013
Post-1996

Line
No.

	<u>PTF Transmission Plant Allocation Factor</u>	<u>CL&P</u>	<u>PSNH</u>	<u>WMECO</u>	<u>TOTAL</u>	<u>Reference</u>
1	PTF Transmission Investment	1,870,692,407	364,557,343	151,347,756	2,386,597,506	W/S 3A,3B,3C line 1
2	Total Transmission Investment	<u>2,549,391,725</u>	<u>491,855,190</u>	<u>242,576,350</u>	<u>3,283,823,265</u>	FF1 page 206-207 ln 58
3	Percent Allocation (Line 1/ Line 2)	<u>73.3780%</u>	<u>74.1188%</u>	<u>62.3918%</u>	<u>72.6774%</u>	
	<u>Plant Allocation Factor</u>					
4	Total Transmission Investment (Line 2)	2,549,391,725	491,855,190	242,576,350	3,283,823,265	
5	<i>plus Transmission-Related General Plant (Line 2 of Wkst. 3)</i>	<u>87,347,012</u>	<u>40,705,818</u>	<u>13,966,462</u>	<u>142,019,292</u>	W/S 3A,3B,3C line 2
6	<i>= Revised Numerator (Line 4 + Line 5)</i>	<u>2,636,738,737</u>	<u>532,561,008</u>	<u>256,542,812</u>	<u>3,425,842,557</u>	
7	Total Plant in Service	7,056,421,479	3,054,013,243	981,963,729	11,092,398,451	FF1 206-207 ln 100
8	Percent Allocation (Line 6 / Line 7)	<u>37.3665%</u>	<u>17.4381%</u>	<u>26.1255%</u>	<u>30.8846%</u>	

Northeast Utilities System Companies'
Transmission Support Revenues and Expenses - 2011
for Rates billed June 1, 2012 - May 31, 2013
Pre-1997

Worksheet 7

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	FERC Form 1	CL&P		PSNH		WMECO		TOTAL	
			Revenues (a)	Expenses (b)	Revenues (a)	Expenses (b)	Revenues (a)	Expenses (b)	Revenues (a)	Expenses (b)
NSTAR	345 kV Sherman - Medway 336 line									-
	115 kV Somerville 402 Substation									-
	115/345 kV North Cambridge 509 Substation									-
	345 kV Golden Hills -Mystic 389 (x&y) line									-
	West Medway 345 kV breaker									-
	115 kV Millbury-Medway 201 line									-
	HQ Phase II - AC in MA	FF1 page 332 In. 7		85,513		45,422		17,951		148,886
	345 kV "stabilizer" 342 line									-
	345 kV Walpole - Medway 325 line									-
	345 kV Carver - Walpole 331 line									-
	345 kV Jordan Rd - Canal 342 line									-
CEC	Second Canal line									-
	345 kV Pilgrim-Bridgewater - 355 line									-
	345 kV Myles Standish - Canal 342 line									-
										-
CMP	345 kV Buxton-South Gorham 386 line					3,006				3,006
	115 kV Wyman 164-167 lines					6,526				6,526
	115 kV Saco Valley									-
										-
EUA	345 kV Carver - Walpole 331 line									-
	345 kV Medway - Bridgewater 344 Line									-
	Northern Rhode Island transmission									-
										-
NEP	Chester SVC	FF1 page 332 In. 13		516,745		274,477		108,478		899,700
	Comerford 115 kV Substation									-
	345 kV Sandy-Tewksbury 337 line									-
	345 kV Tewksbury-Woburn 338 line									-
	115 kV Tewksbury - Woburn M139 line									-
	115 kV Tewksbury - Woburn N140 line									-
	Moore 115 kV Substation	FF1 page 332.2 In. 4				13,319				13,319
	HQ Phase II - AC in MA	FF1 page 332 In. 6		1,225,954		651,185		257,357		2,134,496
	345 kV Golden Hills-Mystic 349 line									-
	345 kV NH/MA border-Tewksbury 394 line									-
	115 kV Read - Washington V148 line									-
NU	345 kV 363, 369 and 394 Seabrook lines	FF1 page 330.1 In. 3			400,011				400,011	-
	Fairmont 115 kV Substation									-
	345 kV Millstone-Manchester 310 line	FF1 page 330.1 In. 3	1,349,489						1,349,489	-
	UI Substations									-
	Black Pond	FF1 page 330.1 In 4	176,928						176,928	-
Total =			1,526,417	1,828,212	400,011	993,935	-	383,786	1,926,428	3,205,933

Amount by which Support Expense exceeds Support Revenues
 (To Worksheet 3, Line 21, Column 5)

301,795

593,924

383,786

1,279,505

Connecticut Light and Power Company										
Substations and Lines										
PTF Investment as of 12/31/11 (101 + 106)										
	350	352	353	354	355	356	357	358	359	Grand Total
1977 + PRIOR	25,992,489.48	1,940,766.08	42,109,684.56	17,890,085.63	38,901,695.53	34,838,047.97	817,910.81	5,448,469.52	341,207.64	168,280,357.22
1978	4,668,677.43	409,060.99	3,995,194.68	124,018.10	5,791,654.09	5,014,254.09	0.00	0.00	0.00	20,002,859.39
1979	5,625,322.72	0.00	653,085.11	0.00	3,011,212.50	1,408,337.25	0.00	0.00	53,118.62	10,751,076.20
1980	312,323.69	0.00	1,175,647.97	1,207,553.88	1,165,524.66	1,783,085.97	0.00	0.00	0.00	5,644,136.17
1981	838,754.77	410,688.59	7,352,957.12	3,363,183.07	3,778,233.85	2,871,087.62	0.00	0.00	445,359.14	19,060,264.16
1982	1,321,414.52	10,210.30	935,543.46	0.00	4,342,413.66	3,137,589.63	0.00	0.00	457,303.27	10,204,474.84
1983	144,379.22	97,133.02	3,072,189.48	1,633,362.93	1,373,080.64	943,747.96	0.00	452,348.46	114,420.29	7,830,662.00
1984	23,940.59	127,646.92	2,730,399.23	736,432.67	13,538.77	697,887.08	0.00	0.00	105,693.03	4,435,538.28
1985	0.00	660,019.24	7,420,433.48	254,460.70	12,716,402.36	11,134,043.31	0.00	14,035.59	2,086,693.18	34,286,087.86
1986	17.45	14,718.73	4,675,098.94	0.00	203,272.05	608,619.41	0.00	0.00	7,934.56	5,509,661.14
1987	26,687.13	9,136.99	1,290,456.84	220,544.60	2,282,408.84	1,192,027.94	0.00	0.00	141,730.14	5,162,992.48
1988	12,321.82	94,980.56	3,403,883.28	0.00	419,496.90	813,077.54	0.00	0.00	247,458.25	4,991,218.35
1989	13,407.54	204,916.35	715,262.56	180,966.57	2,241,153.50	1,818,485.72	0.00	23,806.86	552,449.96	5,750,449.06
1990	54,227.47	175,832.80	7,878,319.48	428,506.43	580,138.86	814,674.48	0.00	0.00	96,769.87	10,028,469.39
1991	893,384.98	8,638.88	7,572,072.99	92,885.29	6,010,808.09	5,941,696.63	0.00	0.00	1,288,940.98	21,808,427.84
1992	42,485.41	9,975.95	2,150,800.20	0.00	2,596,097.44	1,534,439.82	0.00	0.00	744,782.51	7,078,581.33
1993	1,193.02	0.00	870,629.77	140,492.94	14,639,277.63	2,889,659.96	0.00	0.00	19,686.26	18,560,939.58
1994	(15,032.07)	0.00	2,380,228.59	0.00	390,839.13	168,063.14	0.00	0.00	90,525.06	3,014,623.85
1995	2,545.44	36,807.38	152,980.53	0.00	347,481.69	256,664.17	0.00	0.00	0.00	796,479.21
1996	0.00	93,274.62	1,316,197.14	0.00	324,259.63	72,341.50	0.00	0.00	0.00	1,806,072.89
	39,958,540.61	4,303,807.40	101,851,065.41	26,272,492.81	101,128,989.82	77,937,831.19	817,910.81	5,938,660.43	6,794,072.76	365,003,371.25
1997	39,442.79	38,745.58	4,988,930.38	112,607.52	118,897.46	4,837,106.76	0.00	0.00	0.00	10,135,730.49
1998	(6,147.32)	52,546.91	384,955.71	0.00	113,374.45	105,664.19	0.00	0.00	0.00	650,393.94
1999	0.00	0.00	511,208.03	28,802.26	26,718.64	6,688.86	0.00	0.00	0.00	573,417.79
2000	0.00	0.00	2,603,480.80	0.00	256,383.81	5,663.06	136,633.03	179,004.16	61,360.97	3,242,525.83
2001	822,820.03	241,612.95	17,603,052.18	0.00	1,269,539.97	28,447.99	0.00	0.00	0.00	19,965,473.13
2002	0.00	92,990.17	6,100,646.08	184,907.20	1,932,736.37	2,939,424.59	0.00	0.00	0.00	11,250,704.41
2003	(30,877.09)	186,064.96	13,881,090.03	55,332.28	8,873,825.87	2,570,587.65	0.00	0.00	0.00	25,536,023.70
2004	608,926.57	1,964,075.07	56,433,556.94	0.00	2,261,294.57	377,603.79	1,058,908.61	1,180,509.94	18,824.61	63,903,700.09
2005	3,146,607.24	4,568,638.60	77,282,918.97	0.00	3,485,877.13	3,110,943.64	16,291,589.29	9,150,257.10	0.00	117,036,831.97
2006	11,343,316.97	7,275,197.38	80,605,597.10	0.00	20,110,321.49	9,020,162.39	20,432,422.46	67,443,769.08	3,924,497.21	220,155,284.07
2007	10,995,797.77	3,674,057.94	75,925,219.40	0.00	74,824,617.41	44,987,996.81	0.00	0.00	29,274.47	210,436,963.81
2008	3,210,670.58	9,484,748.66	211,485,436.64	377,524.85	79,097,441.57	49,501,045.93	355,099,814.26	303,008,984.45	18,156,910.99	1,029,422,577.93
2009	1,327,604.58	6,925,977.02	49,105,365.23	0.00	7,631,127.62	594,163.12	51,804.71	16,940.16	148,041.11	65,801,023.55
2010	1,400,778.02	757,247.00	21,735,830.92	0.00	10,681,685.90	2,025,460.08	0.00	1,341,534.95	4,141,286.56	42,083,823.43
2011	1,036,824.70	7,791,765.49	30,184,553.67	14,947.35	5,000,689.80	6,381,382.93	0.00	33,128.70	54,639.98	50,497,932.62
Post-1996	33,895,764.85	43,053,667.73	648,831,842.09	774,121.46	215,684,532.07	126,492,341.79	393,071,172.35	382,354,128.54	26,534,835.89	1,870,692,406.77
Grand Total	73,854,305.46	47,357,475.13	750,682,907.50	27,046,614.27	316,813,521.89	204,430,172.99	393,889,083.16	388,292,788.97	33,328,908.65	2,235,695,778.02

PSNH										
Substations and Lines										
PTF Investment as of 12/31/11 (101 + 106)										
	<u>350</u>	<u>352</u>	<u>353</u>	<u>354</u>	<u>355</u>	<u>356</u>	<u>357</u>	<u>358</u>	<u>359</u>	<u>Grand Total</u>
1977 + PRIOR	6,820,185.44	1,651,045.63	10,397,100.41	4,984,250.97	14,258,981.50	13,278,093.93	0.00	0.00	124,519.85	51,514,177.74
1978	139,993.54	3,539.39	258,080.43	0.00	111,091.68	74,446.32	0.00	0.00	0.00	587,151.36
1979	14,628.64	1,061.97	206,890.20	0.00	20,149.60	7,987.37	0.00	0.00	0.00	250,717.78
1980	1,509,193.04	24,434.23	973,961.14	3,683,253.81	130,557.04	2,446,589.80	0.00	0.00	468,079.93	9,236,068.98
1981	0.00	0.00	41,352.99	0.00	55,105.42	8,828.28	0.00	0.00	0.00	105,286.69
1982	18.16	0.00	31,511.81	0.00	119,784.62	9,531.48	0.00	0.00	15,557.34	176,403.41
1983	3,063,758.36	4,803.81	494,215.70	0.00	6,712,752.36	4,147,566.73	0.00	0.00	58,959.34	14,482,056.30
1984	1,251.27	0.00	363,214.30	0.00	31,174.37	3,868.27	0.00	0.00	0.00	399,508.21
1985	41.35	0.00	80,135.34	0.00	180,351.54	30,518.62	0.00	0.00	0.00	291,046.85
1986	0.00	575.06	123,524.29	0.00	284,255.28	131,783.31	0.00	0.00	0.00	540,137.94
1987	772,440.36	0.00	11,192.40	0.00	136,774.99	25,273.81	0.00	0.00	3,785.03	949,466.59
1988	3,609.60	0.00	0.00	965,848.51	956,126.76	1,500,829.53	0.00	0.00	0.00	3,426,414.40
1989	14,647.25	0.00	187,015.22	0.00	375,064.19	91,236.57	0.00	0.00	1,113.97	669,077.20
1990	0.00	5,566.96	165,589.80	0.00	313,413.43	10,127.91	0.00	0.00	3,015.40	497,713.50
1991	16,694.54	0.00	23,967.19	0.00	321,114.13	58,253.11	0.00	0.00	6,908.16	426,937.13
1992	389.00	0.00	32,577.96	0.00	404,513.81	58,366.32	0.00	0.00	0.00	495,847.09
1993	1,139,182.15	0.00	450,230.71	0.00	1,506,017.31	1,564,499.00	0.00	0.00	0.00	4,659,929.17
1994	559,024.64	22,945.73	67,770.32	0.00	364,912.43	67,024.43	0.00	0.00	10,622.94	1,092,300.49
1995	0.00	0.00	96,500.03	0.00	105,310.72	147,016.99	0.00	0.00	0.00	348,827.74
1996	12,216.10	0.00	469,922.82	0.00	60,177.02	(209,101.66)	0.00	0.00	8,428.10	341,642.38
Pre-1997	14,067,273.44	1,713,972.79	14,474,753.05	9,633,353.29	26,447,628.20	23,452,740.12	0.00	0.00	700,990.06	90,490,710.96
1997	16,059.00	0.00	166,533.03	0.00	0.00	0.00	0.00	0.00	0.00	182,592.03
1998	0.00	0.00	180,500.93	0.00	34,083.95	4,290.69	0.00	0.00	0.00	218,875.57
1999	0.00	0.00	469,871.03	0.00	435,301.73	35,742.50	0.00	0.00	0.00	940,915.26
2000	2,048.65	0.00	56,646.89	0.00	600,090.39	99,376.72	0.00	0.00	0.00	758,162.65
2001	1,850.00	0.00	1,203,812.01	0.00	1,939,565.20	986,743.91	0.00	0.00	0.00	4,131,971.12
2002	17.06	53,846.94	2,223,201.40	0.00	1,323,131.65	340,583.63	0.00	0.00	0.00	3,940,780.68
2003	984,130.03	120,281.47	13,849,379.48	0.00	3,907,008.02	1,490,494.91	0.00	0.00	0.00	20,351,293.91
2004	840,294.21	863,364.53	16,819,013.16	0.00	2,690,432.38	941,348.68	0.00	0.00	0.00	22,154,452.96
2005	731,133.17	1,100,536.63	13,013,669.70	0.00	3,316,986.24	1,535,933.75	0.00	0.00	0.00	19,698,259.48
2006	533,133.16	417,654.94	14,276,873.79	0.00	4,374,689.42	1,775,394.93	0.00	0.00	0.00	21,377,746.24
2007	5,012.50	416,869.30	21,042,117.69	48,014.31	17,662,667.30	4,424,350.60	0.00	0.00	0.00	43,599,031.70
2008	0.00	8,948,645.80	49,793,040.06	23,769.94	7,688,691.14	4,637,663.29	0.00	0.00	0.00	71,091,810.23
2009	5,203.01	2,026,979.54	47,170,397.11	0.00	7,022,272.21	10,384,455.95	0.00	0.00	7,337.13	66,616,644.95
2010	1,081,933.09	951,661.66	12,910,031.75	0.00	5,977,324.45	1,707,037.62	0.00	0.00	23,143.45	22,651,132.01
2011	0.00	1,310,497.77	47,831,621.97	0.00	12,851,107.96	4,791,536.87	0.00	0.00	58,909.77	66,843,674.34
Post-1996	4,200,813.87	16,210,338.56	241,006,710.01	71,784.25	69,823,352.04	33,154,954.05	0.00	0.00	89,390.35	364,557,343.13
Grand Total	18,268,087.31	17,924,311.35	255,481,463.06	9,705,137.54	96,270,980.24	56,607,694.17	0.00	0.00	790,380.41	455,048,054.08

Western Massachusetts Electric Company										
Substations and Lines										
PTF Investment as of 12/31/11 (101 + 106)										
	<u>350</u>	<u>352</u>	<u>353</u>	<u>354</u>	<u>355</u>	<u>356</u>	<u>357</u>	<u>358</u>	<u>359</u>	<u>Grand Total</u>
1977 + prior	9,306,872.81	1,290,806.16	15,746,429.73	1,051,290.20	9,642,287.23	13,584,323.30	29,748.54	1,169,976.09	-	51,821,734.06
1978	-	-	21,590.24	-	-	7,536.32	-	-	-	29,126.56
1979	10,284.94	-	453,604.50	-	178,455.10	86,353.76	-	-	5,614.05	734,312.35
1980	1,449.53	-	1,032,398.99	-	-	1,909.38	-	-	-	1,035,757.90
1981	12,424.35	-	135,354.18	-	-	-	-	-	-	147,778.53
1982	50,999.36	-	311,440.53	-	-	13,901.64	-	-	-	376,341.53
1983	-	15,300.56	328,138.82	-	-	-	-	-	-	343,439.38
1984	73,847.45	-	1,072,552.71	-	72,572.55	132,518.95	-	-	-	1,351,491.66
1985	199,055.53	17,437.12	80,270.68	-	40,356.20	10,366.45	-	-	-	347,485.98
1986	-	-	360,654.97	-	-	61,388.46	-	-	-	422,043.43
1987	2,041.90	-	189,856.73	-	-	37,797.17	-	-	-	229,695.79
1988	1,125.58	-	657,385.22	-	39,865.01	33,013.71	-	-	25,912.84	757,302.36
1989	1,477.73	-	137,845.79	-	362,317.19	113,378.48	-	-	-	615,019.19
1990	9,163.43	-	21,366.08	-	97,580.99	33,171.77	-	-	-	161,282.27
1991	-	-	112,908.39	-	266,055.97	101,979.43	-	-	-	480,943.79
1992	-	-	353,017.16	-	183,464.03	15,808.38	-	-	-	552,289.57
1993	-	-	138,279.75	-	52,120.46	290,094.29	-	-	-	480,494.50
1994	-	22,086.54	20,973.47	-	166,096.06	45,255.98	-	-	-	254,412.05
1995	-	-	131,854.41	-	3,830.17	-	-	27,888.96	-	163,573.54
1996	-	16,412.76	-	-	-	213,574.66	-	-	-	229,987.42
Pre-1997	9,668,742.60	1,362,043.14	21,305,922.34	1,051,290.20	11,105,000.96	14,782,372.13	29,748.54	1,197,865.05	31,526.89	60,534,511.85
1997	-	-	725,121.85	-	414,195.88	2,977,961.82	-	-	-	4,117,279.55
1998	15,233.06	-	18,704.50	-	-	-	-	-	-	33,937.56
1999	-	-	1,756,926.89	-	1,928,894.28	2,331,629.52	-	-	-	6,017,450.69
2000	-	2,488.27	161,109.67	-	61,315.74	-	-	-	25,475.05	250,388.73
2001	-	-	1,969,495.00	-	13,159.84	95,408.84	-	-	-	2,078,063.68
2002	-	77,480.18	3,257,381.14	-	388,521.22	90,676.02	-	-	-	3,814,058.56
2003	-	-	2,336,295.21	-	67,136.37	9,154.96	-	-	-	2,412,586.54
2004	-	60,019.87	5,188,169.56	-	854,457.36	148,753.14	-	-	4,668.80	6,256,068.73
2005	-	49,502.55	8,183,067.89	-	204,792.77	-	-	-	-	8,437,363.21
2006	-	-	8,749,972.38	-	458,963.84	169,031.15	-	-	22,539.43	9,400,506.80
2007	900.03	-	6,658,589.04	-	198,528.56	686,951.86	-	-	4,728.76	7,549,698.24
2008	1,762.03	53,365.73	5,937,735.20	-	4,056,325.76	373,039.45	-	-	12,386.05	10,434,614.22
2009	775,505.33	269,109.12	8,966,390.13	-	8,375,651.16	1,181,622.03	-	-	-	19,568,277.77
2010	458,602.20	-	9,334,392.53	-	10,680,985.28	480,184.14	-	355,107.85	5,885.39	21,315,157.39
2011	18,031.97	204,158.57	6,690,785.65	154,924.71	35,769,880.95	5,849,747.44	265,500.52	662,272.09	47,002.18	49,662,304.08
Post-1996	1,270,034.62	716,124.29	69,934,136.64	154,924.71	63,472,809.01	14,394,160.37	265,500.52	1,017,379.94	122,685.66	151,347,755.76
Grand Total	10,938,777.22	2,078,167.43	91,240,058.97	1,206,214.91	74,577,809.97	29,176,532.50	295,249.06	2,215,244.99	154,212.55	211,882,267.61

Transmission Related Taxes and Fees						
Calendar Year 2011						
Ln.	Tax - Description	CL&P	PSNH	WMECO	TOTAL	Reference From
1	CT Gross Earnings Tax	15,073,781	-	-	15,073,781	FF1 page 262 FN
2	CT Insurance Premium Excise Tax	111,395	8,071	4,203	123,669	
3	NH Excise Tax	-	15,438	-	15,438	
4	Fed. Excise Tax	-	-	-	-	
5	Mass. Excise Tax	50	9	6	65	
6	Corporation Business Tax	-	-	1,491	1,491	
7	MA Sales Tax	3	-	795	798	
8	CT Sales Tax	(643,303)	6,367	5,570	(631,366)	
9	NH Business Enterprise Tax	29,048	113,199	3,504	145,751	
10	NY Business Franchise Tax	-	-	-	-	
11	Federal Highway use Tax	-	-	-	-	
12	TOTAL (sum of lines 1 to 11)	14,570,974	143,084	15,569	14,729,627	To Total RR Wksht 1
13	Pre-97 %	14.3173%	18.3978%	24.9548%		Worksheet 5A (Pre-1997)
14	Total Pre-97 Related Exp. (line 12x13)	2,086,170	26,324	3,885	2,116,379	To Worksheet 1A line 26
15	Post-96 %	73.3780%	74.1188%	62.3918%		Worksheet 5B (Post-1996)
16	Total Post-96 Related Exp. (line 12x15)	10,691,889	106,052	9,714	10,807,655	To Worksheet 1B line 27

Short Term Through and Out Revenues						
Used in the development of 2011 PTF Revenue Requirements						
		CL&P	PSNH	WMECO	TOTAL	Reference
1	2011 Through and Out Revenues	1,619,776	279,183	134,301	2,033,260	FF1 pg 328.1 - 330.1
2	Less: LT Revs	-	-	-	-	
3	ST T/O Revenues (Line 1-2)	1,619,776	279,183	134,301	2,033,260	
4	Pre-1997 PTF Plant	365,003,371	90,490,711	60,534,512	516,028,594	Attachment A, A1, A2
5	Post-1996 PTF Plant	1,870,692,407	364,557,343	151,347,756	2,386,597,506	Attachment A, A1, A2
6	Total PTF Plant (line 4+ 5)	2,235,695,778	455,048,054	211,882,268	2,902,626,100	
7	Ratio of Pre to Total (Line 4 / 6)	16.33%	19.89%	28.57%		
8	Ratio of Post to Total (Line 5 / 6)	83.67%	80.11%	71.43%		
		100.00%	100.00%	100.00%		
	Revenue Credits Allocated to Pre-1997 and Post-1996 Revenue Requirements:					
9	Pre-1997 Revenue Credit (line 3 * 7)	264,509	55,529	38,370	358,408	To W/S 1-A line 27
10	Post-1996 Revenue Credit (line 3 * 8)	1,355,267	223,654	95,931	1,674,852	To W/S 1-B line 28
11	Total Revenue Credit (line 9+10)	1,619,776	279,183	134,301	2,033,260	

CL+P RSP INVESTMENT BY PLANT ACCOUNT AT 12-31-11				
Plant A/C	Work Order In Service Year	Sum of Gross Plant2	Sum of Accum Depr2	Sum of Net Plant2
35001	2006	667,786.66	0.00	667,786.66
	2007	118,049.25	0.00	118,049.25
	2008	0.00	0.00	0.00
35001 Total		785,835.91	0.00	785,835.91
35002	2004	423,777.17	41,964.69	381,812.48
	2005	2,350,091.18	205,434.65	2,144,656.53
	2006	6,029,794.95	454,564.10	5,575,230.85
	2007	10,866,768.33	683,535.46	10,183,232.87
	2008	646,688.13	32,284.52	614,403.61
	2009	1,320,946.74	48,095.74	1,272,851.00
	2010	605,307.25	13,510.37	591,796.88
	2011	433,543.46	3,297.58	430,245.88
35002 Total		22,676,917.21	1,482,687.11	21,194,230.10
35016	2004	0.00	0.00	0.00
	2006	4,546,692.68	0.00	4,546,692.68
35016 Total		4,546,692.68	0.00	4,546,692.68
35017	2005	0.00	0.00	0.00
	2007	0.00	0.00	0.00
	2008	410,775.47	20,507.09	390,268.38
35017 Total		410,775.47	20,507.09	390,268.38
352	2004	1,161,779.38	208,377.33	953,402.05
	2005	4,433,913.69	699,865.60	3,734,048.09
	2006	7,254,976.84	985,142.00	6,269,834.84
	2007	3,541,065.92	400,484.82	3,140,581.10
	2008	9,340,503.18	837,549.65	8,502,953.53
352 Total		25,732,239.01	3,131,419.40	22,600,819.61
353	2004	51,371,363.41	6,607,854.32	44,763,509.09
	2005	66,663,495.85	7,610,595.97	59,052,899.87
	2006	68,448,548.78	6,781,572.12	61,666,976.66
	2007	52,546,952.10	4,375,560.03	48,171,392.07
	2008	187,816,243.28	12,522,379.45	175,293,863.82
	2009	370,039.18	18,195.47	351,843.71
353 Total		427,216,642.59	37,916,157.36	389,300,485.23
354	2008	75,434.70	6,952.25	68,482.45
354 Total		75,434.70	6,952.25	68,482.45
355	2004	233,478.02	64,925.88	168,552.14
	2005	2,569,188.47	616,079.52	1,953,108.95
	2006	17,448,331.55	3,523,390.97	13,924,940.58
	2007	69,621,412.40	11,454,641.79	58,166,770.61
	2008	76,712,157.95	9,786,979.33	66,925,178.62
355 Total		166,584,568.39	25,446,017.48	141,138,550.90
356	2004	163,768.35	37,648.34	126,120.01
	2005	2,669,039.42	526,525.86	2,142,513.56
	2006	5,483,973.68	906,109.68	4,577,864.00
	2007	34,675,870.47	4,640,966.50	30,034,903.97
	2008	49,644,430.46	5,120,420.38	44,524,010.08
356 Total		92,637,082.38	11,231,670.76	81,405,411.62
357	2004	1,058,908.61	111,423.90	947,484.71
	2005	16,291,589.29	1,556,997.45	14,734,591.84
	2006	20,432,422.46	1,736,990.68	18,695,431.78
	2007	0.00	0.00	0.00
	2008	355,099,815.81	21,452,950.57	333,646,865.24
357 Total		392,882,736.16	24,858,362.60	368,024,373.57
358	2004	1,180,509.94	59,674.60	1,120,835.34
	2005	9,150,257.10	443,709.70	8,706,547.40
	2006	67,217,115.44	3,090,189.93	64,126,925.52
	2007	0.00	0.00	0.00
	2008	303,008,984.45	14,930,937.21	288,078,047.23
358 Total		380,556,866.93	18,524,511.44	362,032,355.49
359	2006	3,875,097.81	307,221.66	3,567,876.15
	2008	18,112,232.40	934,832.63	17,177,399.77
359 Total		21,987,330.21	1,242,054.29	20,745,275.92
Grand Total		1,536,093,121.64	123,860,339.77	1,412,232,781.86

PSNH RSP INVESTMENT BY PLANT ACCOUNT AT 12-31-11				
Plant A/C	Year	Sum of Gross Plant2	Sum of Accum Depr2	Sum of Net Plant2
350	2007	5,012.50	0.00	5,012.50
350 Total		5,012.50	0.00	5,012.50
352	2006	401,937.67	36,730.28	365,207.39
	2007	416,869.30	31,383.62	385,485.68
	2008	8,203,611.74	483,766.58	7,719,845.16
352 Total		9,022,418.71	551,880.48	8,470,538.23
353	2004	14,069,510.91	1,817,332.42	12,252,178.50
	2005	5,432,171.26	622,210.95	4,809,960.31
	2006	11,528,793.49	1,145,064.78	10,383,728.71
	2007	14,237,722.52	1,187,914.69	13,049,807.83
	2008	36,249,418.34	2,421,144.68	33,828,273.66
353 Total		81,517,616.52	7,193,667.51	74,323,949.00
355	2004	1,684,384.08	318,787.20	1,365,596.88
	2005	145,459.57	23,884.74	121,574.83
	2006	3,121,875.64	434,574.35	2,687,301.29
	2007	16,838,977.22	1,923,638.63	14,915,338.59
	2008	3,905,123.42	348,610.65	3,556,512.77
355 Total		25,695,819.93	3,049,495.57	22,646,324.36
356	2004	741,149.36	149,758.69	591,390.67
	2005	38,143.60	6,541.76	31,601.84
	2006	1,555,946.54	221,144.76	1,334,801.78
	2007	4,126,890.94	470,463.13	3,656,427.81
	2008	1,669,751.37	145,494.35	1,524,257.02
356 Total		8,131,881.81	993,402.69	7,138,479.12
Grand Total		124,372,749.47	11,788,446.25	112,584,303.21

WMECO RSP INVESTMENT BY PLANT ACCOUNT AT 12-31-11				
Plant A/C	Year	Sum of Gross Plant2	Sum of Accum Depr2	Sum of Net Plant2
353	2004	3,551,718.67	487,526.23	3,064,192.44
	2005	3,055,668.68	372,224.35	2,683,444.32
	2006	4,654,941.92	491,556.42	4,163,385.50
	2008	1,095,892.69	77,367.33	1,018,525.36
Grand Total		12,358,221.96	1,428,674.33	10,929,547.63

CL+P ADVANCED TECHNOLOGY INVESTMENT AT 12-31-11					
Work Order Description	Plant A/C	Work Order In Service Year	Gross Plant	Accum Depr	Net Plant
BRIDGEPORT 2006 ACQUIRED EASEMENTS SEG 3 MN345KV	35002	2006	551,702.94	41,590.86	510,112.08
FAIRFIELD 2006 ACQUIRED EASEMENTS MN345KV SEG4	35002	2006	1,276,433.81	96,225.66	1,180,208.15
WESTPORT 2006 EASEMENTS ACQUIRED MN345KV SEG4	35002	2006	1,471,790.40	110,952.88	1,360,837.52
NORWALK 2006 EASEMENTS ACQUIRED MN345KV SEG 4	35002	2006	871,657.40	65,711.05	805,946.35
MN 345KV SEG1 BESECK SWITCH STATION	35389	2007	214,782.79	17,884.86	196,897.93
MN 345KV SEG 3 ROW EASEMENTS	35002	2007	159,437.18	10,028.83	149,408.35
MN 345KV SEG 3 ROW EASEMENTS	35002	2007	329,790.68	20,744.32	309,046.36
MN 345KV SEG 4 ROW EASEMENTS	35002	2007	832,242.54	52,349.26	779,893.28
MN 345KV SEG 4 ROW EASEMENTS	35002	2007	1,969,149.47	123,862.35	1,845,287.12
MN 345KV SEG 4 ROW EASEMENTS	35002	2007	1,100,725.15	69,237.20	1,031,487.95
MN 345KV SEGMENT 2 EAST DEVON S/S-115KV WORK	35389	2008	242,950.15	16,198.36	226,751.79
MN 345KV SEGMENT 2 EAST DEVON S/S-345KV WORK	35389	2008	155,527.35	10,369.57	145,157.78
MN 345KV SEGMENT 2 EAST DEVON S/S-AUTOS	35389	2008	131,699.72	8,780.89	122,918.83
MN 345KV SEGMENT 2 EAST DEVON S/S-AUTOS	35389	2008	167,348.48	11,157.72	156,190.77
MN 345KV SEGMENT 3 EAST DEVON TO SINGER	357	2008	29,727,273.87	1,795,939.35	27,931,334.52
MN 345KV SEGMENT 3 EAST DEVON TO SINGER	358	2008	20,921,098.89	808,296.70	20,112,802.19
MN 345KV SEGMENT 4 SINGER TO NORWALK	357	2008	212,012,309.28	12,808,481.94	199,203,827.34
MN 345KV SEGMENT 4 SINGER TO NORWALK	358	2008	138,385,730.79	5,346,599.12	133,039,131.68
MN 345KV SEGMENT 4 NORWALK SS	35389	2008	132,626.90	8,842.70	123,784.19
MN 345KV SEGMENT 4 NORWALK SS	35389	2008	88,414.55	5,894.91	82,519.64
MN 345KV SEGMENT 4 NORWALK SS	35389	2008	277,778.02	18,520.46	259,257.56
MN 345KV SEGMENT 4 NORWALK SS, SHUNT REACTORS	35389	2008	7,967,373.18	531,213.21	7,436,159.97
MN 345KV SEG 4 ROW EASEMENT LL 543.01 WESTPOR	35002	2008	21,606.96	1,078.68	20,528.28
MN 345KV SEG 3 ROW EASEMENT LL 430_BRIDGEPORT	35002	2009	170,502.97	6,208.02	164,294.95
MN 345KV SEG 3 ROW EASEMENT LL 430.01 BRIDGEPORT	35002	2009	53,105.96	1,933.59	51,172.37
MN 345KV SEG 3 ROW EASEMENT LL 442 & 443	35002	2009	54,542.04	1,985.88	52,556.16
MN 345KV SEG 3 ROW EASEMENT LL 451.02 B'PORT	35002	2009	14,681.15	534.54	14,146.61
MN 345KV SEG 4 ROW EASEMENT LL 421 FAIRFIELD	35002	2009	172,772.58	6,290.66	166,481.92
MN 345KV SEG 4 ROW EASEMENT LL 520 WESTPORT	35002	2009	70,682.00	2,573.54	68,108.46
MN 345KV SEG 3 ROW EASEMENT LL 437 BRIDGEPORT	35002	2010	93,861.12	2,094.97	91,766.15
MN 345KV SEG 3 ROW EASEMENT LL 444 BRIDGEPORT	35002	2010	19,780.99	441.51	19,339.48
MN 345KV SEG 4 ROW EASEMENT LL 518 WESTPORT	35002	2010	146,494.92	3,269.74	143,225.18
MN 345KV SEG 4 ROW EASEMENT LL 523 WESTPORT	35002	2010	97,312.09	2,171.99	95,140.10
MN 345KV SEG 4 ROW EASEMENT LL 541 WESTPORT	35002	2010	91,794.06	2,048.83	89,745.23
MN 345KV SEG 4 ROW EASEMENT LL 543.01 WESTPOR	35002	2010	156,064.07	3,483.33	152,580.74
MN 345KV SEG 4 ROW EASEMENT LL 515 NORWALK	35002	2011	232,761.22	1,770.41	230,990.81
MN 345KV SEG 4 ROW EASEMENT LL 516 NORWALK	35002	2011	200,782.24	1,527.17	199,255.07
TOTAL CL+P ADVANCED TECHNOLOGY ADDITIONS AT 12-31-11			\$ 420,584,587.91	\$ 22,016,295.06	\$ 398,568,292.84

CL&P/WMECO NEEWS Investment Balances as of 12-31-11								
<u>Company</u>	<u>Work Order</u>	<u>Work Order Description</u>	<u>G/L A/C</u>	<u>Plant A/C</u>	<u>Work Order In Service</u>	<u>Gross Plant</u>	<u>Accum Depr</u>	<u>Net Plant</u>
WMECO	402952AB	NEEWS: AGAWAM 115KV CAPACITOR BANKS	10601	353	2011	3,469,798.68	37,717.16	3,432,081.52
	40328901	W SPRINGFIELD-AGAWAM REBUILD 1311 LINE	10101	353	2011	26,748.90	290.76	26,458.14
	40328901	W SPRINGFIELD-AGAWAM REBUILD 1311 LINE	10101	355	2011	9,936,172.66	123,696.40	9,812,476.26
	40328901	W SPRINGFIELD-AGAWAM REBUILD 1311 LINE	10101	356	2011	2,872,495.21	35,694.92	2,836,800.29
	40328902	W SPRINGFIELD-AGAWAM 1412 LINE REBUILD	10101	353	2011	11,614.40	126.26	11,488.14
	40328902	W SPRINGFIELD-AGAWAM 1412 LINE REBUILD	10101	355	2011	8,139,564.21	101,330.25	8,038,233.96
	40328902	W SPRINGFIELD-AGAWAM 1412 LINE REBUILD	10101	356	2011	2,102,509.56	26,126.74	2,076,382.82
	403289AU	NEEWS: AGAWAM UNDERGROUND WORK	10101	357	2011	265,500.52	9,190.88	256,309.64
	403289AU	NEEWS: AGAWAM UNDERGROUND WORK	10101	358	2011	662,272.09	7,214.81	655,057.28
	403289TW	AGAWAM-1412 TERMINAL UPGRADE	10101	353	2011	637,770.55	6,932.65	630,837.90
	403289WS	NEEWS: WEST SPRINGFIELD G08C SS MODS	10101	353	2011	70,791.14	769.51	70,021.63
	403289WU	NEEWS: W. SPRINGFIELD UNDERGROUND WORK	10101	353	2011	240,080.02	2,609.70	237,470.32
WMECO Total						28,435,317.94	351,700.04	28,083,617.90
CL&P	40329301	REBUILD #353 345KV LINE FROM KLEEN TO WRJ	10101	355	2010	1,423,289.38	77,851.20	1,345,438.18
	40329301	REBUILD #353 345KV LINE FROM KLEEN TO WRJ	10101	356	2010	350,026.97	15,299.96	334,727.01
	40330401	310/368 LINE SEPARATION	10601	355	2010	7,958,304.89	435,304.00	7,523,000.89
	40330402	310/368 LINE REBUILD/SEPARATION	10601	355	2010	429,763.57	23,507.24	406,256.33
	40330402	310/368 LINE REBUILD/SEPARATION	10601	356	2010	5,149.72	225.10	4,924.62
	40330403	310/368 LINE REBUILD/SEPARATION	10601	356	2010	1,625,984.30	71,073.12	1,554,911.18
	40330404	310/368 LINE REBUILD MANCHESTER 345KV SS MC	10601	353	2011	353,445.03	3,769.22	349,675.81
	40330405	INSTALL STRUCTURE 10006 FOR 368 LINE	10601	355	2011	590,205.36	10,820.59	579,384.77
CL&P Total						12,736,169.22	637,850.43	12,098,318.79
Grand Total						41,171,487.16	989,550.47	40,181,936.69

NU Transmission 2012 PTF In-Service Forecast
(\$ X 1000)

Company	ISO-NE RSP Project ID	Project Title	Estimated PTF In-Service
CL&P	(a)	NEEWS Projects - CT	\$ 2,485
CL&P	NA	NEEWS CWIP-CT	\$ 77,552
CL&P	N/A	115KV & 345KV Hollow Core Insulator Project	\$ 13,773
CL&P	N/A	Relay Replacements	\$ 10,955
CL&P	N/A	Safety & Obsolete Equipment Replacement Projects	\$ 7,450
CL&P	1227	Southend Ring Bus	\$ 5,734
CL&P	N/A	Break Fix, Tools & Other Annuals	\$ 5,445
CL&P	NA	HVAC in Transmission Control House Buildings	\$ 2,338
CL&P	NA	SMART Grid Synchrophaser	\$ 248
CL&P	NA	Additional PTF Reliability Projects	\$ 4,766
		Total CL&P	\$ 130,746
PSNH	1182	Eagle S/S (Formerly Thorton Ferry S/S)	\$ 20,511
PSNH	(b)	NH 10-YR Projects	\$ 7,654
PSNH	N/A	Safety & Obsolete Equipment Replacement Projects	\$ 3,999
PSNH	N/A	345kV Hollow Core Insulator Replacements	\$ 3,743
PSNH	N/A	Break Fix, Tools & Other Annuals	\$ 2,881
PSNH	N/A	363 Line - Fiber Installation	\$ 2,178
PSNH	N/A	373 & 379 Lines -Live Line Struct Replacements	\$ 1,733
PSNH	N/A	OPGW Projects	\$ 1,665
PSNH	N/A	Streeter Pond Sectionalizing Upgrades	\$ 1,618
PSNH	N/A	Relay Replacements	\$ 1,235
PSNH	N/A	Smart GRID Synchrophasor	\$ 532
PSNH	N/A	Additional PTF Reliability Projects	\$ 1,553
		Total PSNH	\$ 49,302
WMECO	(a)	NEEWS Projects -MA	\$ 142,247
WMECO	NA	NEEWS CWIP-MA	\$ 23,199
WMECO	1216	354 Line Structure Replacement (345kV)	\$ 13,024
WMECO	N/A	1371 Line Structure Replacement (115kV)	\$ 2,278
WMECO	1266	1421 Line Structure Replacement (115kV)	\$ 1,383
WMECO	NA	Break Fix, Tools & Other Annuals	\$ 962
WMECO	NA	HVAC in Transmission Control House Buildings	\$ 530
WMECO	N/A	Safety & Obsolete Equipment Replacement Projects	\$ 506
WMECO	N/A	Smart Grid Synchrophasor	\$ 132
WMECO	NA	Additional PTF Reliability Projects	\$ 1,333
		Total WMECO	\$ 185,594

Total NU PTF Plant In-Service	\$ 264,891
Total NU CWIP	\$ 100,751
Total Northeast Utilities	\$ 365,642

(a) There are multiple RSP numbers associated with the NEEWS projects in both CT and MA (191,196,259,576,687,688,802,810,814,816,818-820,823,826,828,829,1054,1070-1075,1078-1080,1085,1100-1105,1114)

(b) There are multiple RSP numbers associated with the NH 10-YR Projects (1263,1269-1278, 1300, 1302-1325 & 1346)

Note: RSP Project ID base on Approved ISO-NE RSP Project Listing published on March 28, 2012

Northeast Utilities System Companies'
Capitalization - 2011
for Rates billed June 1, 2012 - May 31, 2013

Line No.		CL&P Year End	PSNH Year End	WMECO Year End	Reference
Long Term Debt					
1	Outstanding Bonds (A/C 221 & 224)	2,341,040,834	999,485,000	443,800,000	FF1 pg 257 ln. 33 + pg 256.1, ln 13 fn (PCRB Principal)
2	Premium on LTD (A/C 225)	-	-	-	FF1 page 112 ln. 22
3	Discount on LTD (A/C 226)	4,065,683	1,762,750	1,506,554	FF1 page 112 ln. 23
4	Debt Expense (A/C 181)	15,944,979	8,175,560	3,273,337	FF1 page 111 ln. 69
5	Gain on Reacquired Debt (A/C 257)	-	-	-	FF1 page 113 ln. 61
6	Total LTD (Year End) line 1+2-3-4+5)	2,321,030,172	989,546,690	439,020,109	
7	Total LTD (Beginning of Year / End of Year Average)	2,319,985,131	909,229,941	389,727,569	(Line 6 + prior YE capitalization) / 2
8	Annual Amort of Prem Disc. & Exp. (A/C 428 minus A/C 429)	1,913,705	1,229,356	395,582	FF1 page 117 ln. 63 minus ln. 65
9	Annual Amort of Gain on Reacquired Debt (A/C 429.1)	-	-	-	FF1 page 117 ln. 66
10	Annual Interest Cost (A/C 427)	132,594,878	40,941,550	20,013,133	FF1 pg 257 ln. 33 + pg 256.1, ln 13 fn (PCRB Interest)
11	Total Annual Cost (line 8-9+10)	134,508,583	42,170,906	20,408,715	
12	LTD Cost of Capital (line 11/7)	5.80%	4.64%	5.24%	
Preferred Stock					
13	Outstanding Stock (A/C 204)	116,200,000	-	-	FF1 page 112 ln. 3
14	Premium on PS (A/C 207)	820,027	-	-	G/L
15	Discount on PS (A/C 213)	-	-	-	
16	Unamortized Issue Expense (A/C 214)	303,861	-	-	FF1 page 112 ln. 10
17	Net Proceeds (Year End) line 13+14-15-16	116,716,166	-	-	
18	Net Proceeds (BOY / EOY Average)	116,690,845			(Line 17 + prior YE Net Proceeds) / 2
19	Issue Expense Amortization (A/C 214)	50,643	-	-	FF1 page 112 ln. 10 (diff. in py & cy)
20	Dividend (A/C 437)	5,558,609	-	-	FF1 page 118 ln. 25
21	Annual Expense (line 19+20)	5,609,252	-	-	
22	PS Cost of Capital (line 21/18)	4.81%	-	-	
23	Proprietary Capital (A/C 201 to 219)	2,523,751,942	1,078,362,375	462,300,518	FF1 page 112 ln. 16
24	Common Equity (line 23-17)	2,407,035,776	1,078,362,375	462,300,518	
25	Common Equity (BOY / EOY Average)	2,402,022,246	1,002,404,908	409,942,108	(Line 24 + prior YE common equity) / 2

Cost of Capital Year End 2011

Northeast Utilities System Companies'
AFUDC Equity Amortization in Depreciation - 2011
for Rates billed June 1, 2012 - May 31, 2013
Pre-1997

	<u>Transmission</u> (A)	<u>PTF Allocator</u> (B)	<u>Transmission</u> <u>PTF level</u> (C)=(A)x(B)	<u>General</u> <u>Transmission</u> (D)	<u>PTF Allocator</u> (E)	<u>General</u> <u>PTF level</u> (F)=(D)x(E)	<u>Total at</u> <u>PTF level</u> (G)=(C)+(F)
CL&P	2,112,804	14.3173%	302,496	87,479	14.3173%	12,525	315,021
PSNH	183,147	18.3978%	33,695	21,369	18.3978%	3,931	37,626
WMECO	54,423	24.9548%	13,581	228	24.9548%	57	13,638
	<u>2,350,374</u>		<u>349,772</u>	<u>109,076</u>		<u>16,513</u>	<u>366,285</u>

Northeast Utilities System Companies'
AFUDC Equity Amortization in Depreciation - 2011
for Rates billed June 1, 2012 - May 31, 2013
Post-1996

	<u>Transmission</u> (A)	<u>PTF Allocator</u> (B)	<u>Transmission</u> <u>PTF level</u> (C)=(A)x(B)	<u>General</u> <u>Transmission</u> (D)	<u>PTF Allocator</u> (E)	<u>General</u> <u>PTF level</u> (F)=(D)x(E)	<u>Total at</u> <u>PTF level</u> (G)=(C)+(F)
CL&P	2,112,804	73.3780%	1,550,333	87,479	73.3780%	64,190	1,614,523
PSNH	183,147	74.1188%	135,746	21,369	74.1188%	15,838	151,584
WMECO	54,423	62.3918%	33,955	228	62.3918%	142	34,097
	<u>2,350,374</u>		<u>1,720,034</u>	<u>109,076</u>		<u>80,170</u>	<u>1,800,204</u>

Note: This worksheet represents the "C" component of the Federal and State Income Tax Formula.

Connecticut Light and Power Company					
2011 PTF Activity					
	Beginning				Ending
	Balance			Adjustments/	Balance
<u>Plant Account</u>	<u>1-1-11</u>	<u>Additions</u>	<u>Retirements</u>	<u>Transfers</u>	<u>12-31-11</u>
350	68,758,707.57	1,102,918.07	(3,014.41)	3,995,694.23	73,854,305.46
352	38,944,652.06	8,587,954.14	(105,025.49)	(70,105.58)	47,357,475.13
353	712,797,220.24	20,834,660.15	(4,987,171.03)	22,038,198.14	750,682,907.50
354	27,049,209.73	14,947.35	(17,542.81)	-	27,046,614.27
355	340,092,021.93	12,828,810.68	(28,406,446.54)	(7,700,864.18)	316,813,521.89
356	219,737,443.94	(1,854,635.74)	(13,455,083.16)	2,447.95	204,430,172.99
357	395,434,787.51	(1,539,290.61)	-	(6,413.74)	393,889,083.16
358	387,188,128.91	1,108,846.49	-	(4,186.43)	388,292,788.97
359	29,969,828.95	3,359,079.70	-	-	33,328,908.65
Grand Total	2,219,972,000.85	44,443,290.23	(46,974,283.44)	18,254,770.39	2,235,695,778.03

Public Service Company of New Hampshire					
2011 PTF Activity					
	Beginning				Ending
	Balance			Adjustments/	Balance
<u>Plant Account</u>	<u>1-1-11</u>	<u>Additions</u>	<u>Retirements</u>	<u>Transfers</u>	<u>12-31-11</u>
350	17,538,735.95	(1,357,064.89)	(12,761.91)	2,099,178.16	18,268,087.30
352	15,700,940.57	2,098,543.21	(71,207.03)	196,034.60	17,924,311.35
353	207,662,683.44	47,730,096.80	(802,796.76)	891,479.58	255,481,463.06
354	9,705,137.54				9,705,137.54
355	86,360,540.20	10,402,216.92	(715,790.90)	224,014.02	96,270,980.24
356	53,122,827.75	3,818,015.42	(333,149.00)		56,607,694.17
357	0.00				0.00
358	0.00				0.00
359	705,150.98	75,583.77		9,645.66	790,380.41
Grand Total	390,796,016.41	62,767,391.23	(1,935,705.59)	3,420,352.02	455,048,054.06

Western Massachusetts Electric Company					
2011 PTF Activity					
	Beginning				Ending
	Balance			Adjustments/	Balance
<u>Plant Account</u>	<u>1-1-11</u>	<u>Additions</u>	<u>Retirements</u>	<u>Transfers</u>	<u>12-31-11</u>
350	9,556,550.01	2,820.16	(6,559.40)	1,385,966.45	10,938,777.22
352	1,786,043.59	204,158.57		87,965.27	2,078,167.43
353	82,760,740.99	6,061,633.14	(1,284,944.66)	3,702,629.51	91,240,058.97
354	1,149,771.59	154,924.71	(98,481.39)		1,206,214.91
355	45,284,244.64	29,341,196.10	(47,630.77)		74,577,809.97
356	23,315,226.73	6,329,931.58	(468,625.81)		29,176,532.50
357	31,742.27	265,500.52	(1,993.73)		295,249.06
358	1,197,865.05	1,017,379.94			2,215,244.99
359	107,210.37	47,002.18			154,212.55
Grand Total	165,189,395.24	43,424,546.90	(1,908,235.76)	5,176,561.23	211,882,267.61

Exhibit 1

**Adjusted 2009 and 2010
PTF Revenue Requirement to reflect the
Commission Order in Docket No. FA11-15-000**

The Connecticut Light & Power Company									
Adjustment per FERC Order in Docket No. FA11-15-000									
			Annual True-up Pre-97		Annual True-up Post-96		Total True-up Amount		Reference
	2009								
1	Principal		(\$9,282)		\$ (44,357)		\$ (53,639)		Exhibit 1, page 2
2	Interest		(\$627)		\$ (3,008)		\$ (3,635)		Exhibit 1, page 4
3	Total (line 1 + 2)		\$ (9,909)		\$ (47,365)		\$ (57,274)		
	2010								
4	Principal		\$ 7,027		\$ 34,469		\$ 41,496		Exhibit 1, page 2
5	Interest		\$ 234		\$ 1,148		\$ 1,382		Exhibit 1, page 5
6	Total (line 4 + 5)		\$ 7,261		\$ 35,617		\$ 42,878		
	Total								
7	Principal (line 1 + 4)		(\$2,255)		(\$9,888)		(\$12,143)		
8	Interest (line 2 + 5)		(\$393)		(\$1,860)		(\$2,253)		
9	Total (line 7 + 8)		\$ (2,648)		\$ (11,748)		\$ (14,396)		

As a result of the Commission Order in Docket No. FA11-15-000, CL&P was required to update the general plant depreciation rates used to calculate transmission related general depreciation. This resulted in a change in the depreciation expense previously included in the actual 2009 and 2010 PTF RR (calculated in June 2010 and 2011 respectively). Amounts above include interest calculated through May 31, 2012 in accordance with Section 35.19a.

The Connecticut Light & Power Company									
Adjustment per FERC Order in Docket No. FA11-15-000									
				PRE-97 PTF			POST-96 PTF		
			(1) Total	(2) PTF	(3) = (1)*(2) Pre-97	(4) PTF	(5) = (1)*(4) Post-96		
Line No.			Transmission Adjustment	Allocation Factor	PTF Allocated	Allocation Factor	PTF Allocated		
	<u>2009 Actual</u>								
1	Transmission Depreciation Adjustment		\$ (59,193)	15.6805%	\$ (9,282)	74.9358%	\$ (44,357)		
	<u>2010 Actual</u>								
2	Transmission Depreciation Adjustment		\$ 46,864	14.9945%	\$ 7,027	73.5507%	\$ 34,469		
3	Total Transmission Depreciation Adjustment		\$ (12,329)		\$ (2,255)		\$ (9,888)		

In order to determine the depreciation expense adjustment related to PTF, the total transmission depreciation adjustment was allocated using the plant allocation factors for each year (2009 and 2010).

The Connecticut Light & Power Company							
Interest Calculation Associated with the Adjustment							
per FERC Order in Docket No. FA11-15-000							
(2009 Adjustment)							
PRE-97 & POST 96							
	(A)	(B)	(C)	(D)	(E)	(F)=(C)x(E)	(G)=(D)x(E)
			Balance		FERC Monthly	Interest	
Line	Initial Billing Period	Reference	Pre	Post	Interest Rate	Pre	Post
1	June 2010	(a)	\$ (9,282)	\$ (44,357)	0.27%	\$ (25)	\$ (120)
2	Total through 2nd Qtr.	In. 1 bal. + In. 1 intr.	\$ (9,307)	\$ (44,477)			
3	July 2010	line 2 balance	\$ (9,307)	\$ (44,477)	0.28%	\$ (26)	\$ (125)
4	August 2010	↓	\$ (9,307)	\$ (44,477)	0.28%	\$ (26)	\$ (125)
5	September 2010	↓	\$ (9,307)	\$ (44,477)	0.27%	\$ (25)	\$ (120)
6	Total through 3rd Qtr.	In. 2 bal.+ In. 3+4+5 intr.	\$ (9,384)	\$ (44,847)			
7	October 2010	line 6 balance	\$ (9,384)	\$ (44,847)	0.28%	\$ (26)	\$ (126)
8	November 2010	↓	\$ (9,384)	\$ (44,847)	0.27%	\$ (25)	\$ (121)
9	December 2010	↓	\$ (9,384)	\$ (44,847)	0.28%	\$ (26)	\$ (126)
10	Total through 4th Qtr.	In. 6 bal.+ In. 7+8+9 intr.	\$ (9,461)	\$ (45,220)			
11	January 2011	line 10 balance	\$ (9,461)	\$ (45,220)	0.28%	\$ (26)	\$ (127)
12	February 2011	↓	\$ (9,461)	\$ (45,220)	0.25%	\$ (24)	\$ (113)
13	March 2011	↓	\$ (9,461)	\$ (45,220)	0.28%	\$ (26)	\$ (127)
14	Total through 1st Qtr.	In. 10 bal. + In. 11+12+13 intr.	\$ (9,537)	\$ (45,587)			
15	April 2011	line 14 balance	\$ (9,537)	\$ (45,587)	0.27%	\$ (26)	\$ (123)
16	May 2011	↓	\$ (9,537)	\$ (45,587)	0.28%	\$ (27)	\$ (128)
17	June 2011	↓	\$ (9,537)	\$ (45,587)	0.27%	\$ (26)	\$ (123)
18	Total through 2nd Qtr.	In. 14 bal. + In. 15+16+17 intr.	\$ (9,616)	\$ (45,961)			
19	July 2011	line 18 balance	\$ (9,616)	\$ (45,961)	0.27%	\$ (26)	\$ (124)
20	August 2011	↓	\$ (9,616)	\$ (45,961)	0.28%	\$ (27)	\$ (129)
21	September 2011	↓	\$ (9,616)	\$ (45,961)	0.27%	\$ (26)	\$ (124)
22	Total through 3rd Qtr.	In. 18 bal.+ In. 19+20+21 intr.	\$ (9,695)	\$ (46,338)			
23	October 2011	line 22 balance	\$ (9,695)	\$ (46,338)	0.28%	\$ (27)	\$ (130)
24	November 2011	↓	\$ (9,695)	\$ (46,338)	0.27%	\$ (26)	\$ (125)
25	December 2011	↓	\$ (9,695)	\$ (46,338)	0.28%	\$ (27)	\$ (130)

The Connecticut Light & Power Company							
Interest Calculation Associated with the Adjustment							
per FERC Order in Docket No. FA11-15-000							
(2009 Adjustment)							
PRE-97 & POST 96							
	(A)	(B)	(C)	(D)	(E)	(F)=(C)x(E)	(G)=(D)x(E)
			Balance		FERC Monthly	Interest	
Line	Initial Billing Period	Reference	Pre	Post	Interest Rate	Pre	Post
26	Total through 4th Qtr.	In. 22 bal.+ In. 23+24+25 intr.	\$ (9,775)	\$ (46,723)			
27	January 2012	line 26 balance	\$ (9,775)	\$ (46,723)	0.28%	\$ (27)	\$ (131)
28	February 2012		\$ (9,775)	\$ (46,723)	0.26%	\$ (25)	\$ (121)
29	March 2012	↓	\$ (9,775)	\$ (46,723)	0.28%	\$ (27)	\$ (131)
30	Total through 1st Qtr.	In. 26 bal. + In. 27+28+29 intr.	\$ (9,854)	\$ (47,106)			
31	April 2012	line 30 balance	\$ (9,854)	\$ (47,106)	0.27%	\$ (27)	\$ (127)
32	May 2012	↓	\$ (9,854)	\$ (47,106)	0.28%	\$ (28)	\$ (132)
33	Total Surcharge/(Refund)	line 30 bal. + 31+32 intr.				\$ (9,909)	\$ (47,365)
(a)	Pre-97 Charge/(Refund)	(9,282)					
	Post-96 Charge (Refund)	(44,357)					
(b)	To Check	Total	Interest	Principle			
		line 33	sum of In. 1 to 32	In. 1, Col C and D			
	Pre	\$ (9,909)	\$ (627)	\$ (9,282)			
	Post	\$ (47,365)	\$ (3,008)	\$ (44,357)			
	Total	\$ (57,274)	\$ (3,635)	\$ (53,639)			

The Connecticut Light & Power Company							
Interest Calculation Associated with the Adjustment							
per FERC Order in Docket No. FA11-15-000							
(2010 Adjustment)							
PRE-97 & POST-96							
	(A)	(B)	(C)	(D)	(E)	(F)=(C)x(E)	(G)=(D)x(E)
			Balance		FERC Monthly	Interest	
Line	Initial Billing Period	Reference	Pre	Post	Interest Rate	Pre	Post
1	June 2011	(a)	\$ 7,027	\$ 34,469	0.27%	\$ 19	\$ 93
2	Total through 2nd Qtr.	ln. 1 bal. + ln. 1 intr.	\$ 7,046	\$ 34,562			
3	July 2011	line 2 balance	\$ 7,046	\$ 34,562	0.27%	\$ 19	\$ 93
4	August 2011	↓	\$ 7,046	\$ 34,562	0.28%	\$ 20	\$ 97
5	September 2011	↓	\$ 7,046	\$ 34,562	0.27%	\$ 19	\$ 93
6	Total through 3rd Qtr.	ln. 2 bal.+ ln. 3+4+5 intr.	\$ 7,104	\$ 34,845			
7	October 2011	line 6 balance	\$ 7,104	\$ 34,845	0.28%	\$ 20	\$ 98
8	November 2011	↓	\$ 7,104	\$ 34,845	0.27%	\$ 19	\$ 94
9	December 2011	↓	\$ 7,104	\$ 34,845	0.28%	\$ 20	\$ 98
10	Total through 4th Qtr.	ln. 6 bal.+ ln. 7+8+9 intr.	\$ 7,163	\$ 35,135			
11	January 2012	line 10 balance	\$ 7,163	\$ 35,135	0.28%	\$ 20	\$ 98
12	February 2012	↓	\$ 7,163	\$ 35,135	0.26%	\$ 19	\$ 91
13	March 2012	↓	\$ 7,163	\$ 35,135	0.28%	\$ 20	\$ 98
14	Total through 1st Qtr.	ln. 10 bal. + ln. 11+12+13 intr.	\$ 7,222	\$ 35,422			
15	April 2012	line 14 balance	\$ 7,222	\$ 35,422	0.27%	\$ 19	\$ 96
16	May 2012	↓	\$ 7,222	\$ 35,422	0.28%	\$ 20	\$ 99
17	Total Surcharge/(Refund)	line 14 bal. + 15+16 intr.				\$ 7,261	\$ 35,617
(a)	Pre-97 Charge/(Refund)	7,027					
	Post-96 Charge (Refund)	34,469					
(b)	To Check	Total	Interest	Principle			
		line 17	sum of ln. 1 to 16	ln. 1, Col C and D			
	Pre	\$ 7,261	\$ 234	\$ 7,027			
	Post	\$ 35,617	\$ 1,148	\$ 34,469			
	Total	\$ 42,878	\$ 1,382	\$ 41,496			

Norwood Municipal Light Department

Sheet: Input Panel

Input Panel

Regional Network Service
Annual Transmission Revenue Requirements
per Attachment F of the ISO New England Inc. Open Access Transmission Tariff

Shading denotes an input

Submitted on: 05/14/2012

Revenue Requirements for (year): 2011

Customer: Norwood Municipal Light Department

Customer's NABs Number: 158

Name of Participant responsible for customer's billing: Malcolm McDonald

DUNS number of Participant responsible for customer's billing: 08-421-1572

	Pre-97 Revenue Requirements	Post-96 Revenue Requirements
Total of Attachment F - Sections A through I =	(a)	2,653,119 (f)
Total of Attachment F - Section J - Support Revenue	0 (b)	0 (g)
Total of Attachment F - Section K - Support Expense	0 (c)	0 (h)
Total of Attachment F - Section L through O	0 (d)	0 (i)
Sub Total - Sum (A through I) - J + K + (L through O)	0 (e)=(a)-(b)+(c)+(d)	2,653,119 (j)=(f)-(g)+(h)+(i)
Forecasted Incremental Transmission Revenue Requirements		0 (m)
Annual True-up		86,503 (n)
Interest Charge on Annual True-up	- (l)	2,883 (o)
Total = (e) + (j) + (k) + (l) + (m) + (n) + (o)	0 (p)	2,742,505 (q)
Annual Projected 2008 Revenue Requirement Total = Sum of Pre-97 Revenue Requirements, plus Post-96 Revenue Requirements, plus Annual True-up, and plus Interest on Annual True-up:		2,742,505 (r) = (p)+(q)

Norwood Municipal Light Department
Annual Revenue Requirements of pre-1997 & post-1996 PTF
for costs in 2011 and billed 06/11-05/12

RNS Rate

		Attachment F			
		Reference	Pre 1997	Post 1996	Reference
Line No.	I. INVESTMENT BASE	Section:			
1	Transmission Plant	I (A)(1)(a)	0	15,288,499	Worksheet 3, line 1 column 5
2	General Plant	I (A)(1)(b)	0	291,308	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	I (A)(1)(c)	0	0	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		0	15,579,807	
5	Accumulated Depreciation	I (A)(1)(d)	0	3,407,446	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	I (A)(1)(e)	0	0	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	I (A)(1)(f)	0	0	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	I (A)(1)(g)	0	0	Worksheet 3, line 15 column 5
9	Net Investment (Line 4-5-6+7+8)		0	12,172,361	
10	Prepayments	I (A)(1)(h)	0	2,561	Worksheet 3, line 16 column 5
11	Materials & Supplies	I (A)(1)(i)	0	0	Worksheet 3, line 17 column 5
12	Cash Working Capital	I (A)(1)(j)	0	31,591	Worksheet 3, line 24 column 5
13	Total Investment Base (Line 9+11+12+13)		0	12,206,513	
II. REVENUE REQUIREMENTS					
14	Investment Return and Income Taxes	I (A)	0	976,521	Worksheet 2
15	Depreciation Expense	I (B)	0	379,742	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	I (C)	0	0	Worksheet 4, line 4 column 5
17	Investment Tax Credit	I (D)	0	0	Worksheet 4, line 5 column 5
18	Property Taxes	I (E)	0	932,467	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	I (F)	0	25,158	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	I (G)	0	51,912	Worksheet 4, line 13 column 5
21	Administrative & General Expense	I (H)	0	200,816	Worksheet 4, line 22 column 5
22	Transmission Related Integrated Facilities Charge	I (I)	0	0	
23	Transmission Support Revenue	I (J)	0	0	Worksheet 7
24	Transmission Support Expense	I (K)	0	0	Worksheet 7
25	Transmission Related Expense from Generators	I (L)	0	0	
26	Transmission Related Taxes and Fees Charge	I (M)	0	0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	I (N)	0	0	Txm related Acct 456
28	Transmission Rents Received from Electric Properties	I (O)	0	0	Txm related Acct 454-rent
29	Total Revenue Requirements (Line 14 thru 28)		0	2,566,616	
III. CURRENT CALENDAR YEAR ESTIMATED INCREMENTAL REVENUE REQUIREMENT					
30	Carrying Charge Factor Base Revenue Requirement Numerator			2,653,119	
31	Post-2003 Enhanced Return Addition to Revenue Requirement			-	
32	Total Post-96 PTF Revenue Requirement			2,653,119	
33	Post-96 PTF Transmission Plant in Service			15,910,580	
34	Post-96 Carrying Charge Factor (Post-96 CCF)			16.8%	
35	Forecasted Post-96 PTF Plant Additions			0	
36	Forecasted Post-96 Localized PTF Plant Additions			0	
37	Forecasted Post-96 Pool-Supported PTF Plant Additions			0	
38	Post-96 Estimated Incremental Revenue Requirement			0	

RNS Rate

Norwood Municipal Light Department
FERC Interest Calculation associated with Under / (Over)
True Up and Interest Calculation for 2011

1 2011 Actual Annual RR			0	2,653,119	Input Panel Subtotals
2 2011 Est. Transmission Revenue Requirements (as billed)	6/11-05/12	Appendix C	0	2,566,616	ATRR - Prior Year
3 True-up (Over)/Under (Line 1 - Line 2)			0	86,503	

Pre'97
Post'96

(Overcollection)/Undercollection
\$0
\$86,503

Initial Billing Period	Pre 1997 Balance	Post 1996 Balance	FERC Monthly Interest Rate	Pre 1997 Interest	Post 1996 Interest
June 2011	\$0	\$86,503	0.27%	\$0	\$234
July 2011	0	86,737	0.27%	0	\$234
August 2011	0	86,737	0.28%	0	\$243
September 2011	0	86,737	0.27%	0	\$234
October 2011	0	87,448	0.28%	0	\$245
November 2011	0	87,448	0.27%	0	\$236
December 2011	0	87,448	0.28%	0	\$245
January 2012	0	88,174	0.28%	0	\$247
February 2012	0	88,174	0.26%	0	\$229
March 2012	0	88,174	0.28%	0	\$247
April 2012	0	88,897	0.27%	0	\$240
May 2012	0	88,897	0.28%	0	\$249
		Total Interest		\$0	\$2,883
		True-Up		\$0	\$86,503
		Total TU & Int		\$0	\$89,386

Sheet: Input Panel

NEPOOL Tariff Billing
NEPOOL Annual Transmission Revenue Requirements
per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3

Shading denotes an input

Submitted on:	May 14, 2012
Revenue Requirements for (year):	Calendar Year 2011
Customer:	Norwood Municipal Light Department
Customer's NABs Number:	158
Name of Participant responsible for customer's billing:	Malcolm McDonald
DUNS number of Participant responsible for customer's billing:	08-421-1572

	Pre-97 Revenue Requirements	Post-97 Revenue Requirements
Total of Attachment F - Sections A through I =	(a)	2,653,119 (f)
Total of Attachment F - Section J - Support Revenue	0 (b)	0 (g)
Total of Attachment F - Section K - Support Expense	0 (c)	0 (h)
Total of Attachment F - Section (L through O)	0 (d)	0 (i)
Sub Total - Sum (A through I) - J + K + (L through O)	0 (e)=(a)-(b)+(c)+(d)	2,653,119 (j)

Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements
and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:

2,653,119 (k) = (e) + (j)

Total of Attachment F - Section J - Pre-97 Support Revenue (from above)	0 (b)
Total of Attachment F - Section J - Post-96 Support Revenue (from above-)	0 (g)
Total of Attachment F - Section K - Post-96 Support Expense (from above)	0 (h)

Voting Share Total for Participant's R Value: 2,653,119 (l)=(k)+(b)+(g)-(h)

(for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)

Calendar Year 2011

Shading denotes an input

		Attachment F		
		Reference	Norwood	Reference
Line No.	I. INVESTMENT BASE	Section:		
1	Transmission Plant	(A)(1)(a)	15,910,580	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	252,264	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		16,162,844	
5	Accumulated Depreciation	(A)(1)(d)	3,478,114	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	0	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	0	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	0	Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		12,684,730	
10	Prepayments	(A)(1)(h)	2,037	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	0	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	34,832	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		12,721,599	
II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	1,017,728	Worksheet 2
15	Depreciation Expense	(B)	403,168	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	0	Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)	0	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	932,467	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	21,100	Worksheet 4, line 17 column 5
20	Operation & Maintenance Expense	(G)	109,467	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	169,189	Worksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	0	Worksheet 7
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	0	
28	Transmission Rents Received from Electric Property	(O)	0	
29	Total Revenue Requirements (Line 14 thru 28)		2,653,119	

Norwood Municipal Light Department**Annual Revenue Requirements****Calendar Year 2011**

Shading denotes an input

	<u>CAPITALIZATION</u> <u>12/31/2007</u>	<u>CAPITALIZATION</u> <u>RATIOS</u>	<u>COST OF</u> <u>CAPITAL</u>	<u>COST OF</u> <u>CAPITAL</u>	<u>EQUITY</u> <u>PORTION</u>
LONG-TERM DEBT	\$ 61,150,000	100.00%	8.00%	8.00%	
PREFERRED STOCK	0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	0	0.00%	0.00%	0.00%	0.00%
TOTAL INVESTMENT RETURN	\$ <u>61,150,000</u>	<u>100.00%</u>		<u>8.00%</u>	<u>0.00%</u>

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0800

(b) Federal Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / \text{Federal Income Tax Rate}}{1} \right) \times \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}}$$

=
$$\left(\frac{0.0000 + \left(\frac{0 + 0}{12,721,599} \right)}{1} \right) \times \frac{0}{0}$$

= 0.0000000

(c) State Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / \text{Federal Income Tax Rate}}{1} \right) + \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}} \times \text{State Income Tax Rate}$$

=
$$\left(\frac{0.0000 + \left(\frac{0 + 0}{12,721,599} \right)}{1} \right) + \frac{0.0000000}{0} \times 0$$

= 0.0000000

(a)+(b)+(c) **Cost of Capital Rate** = 0.0800000

	<u>(PTF)</u>	
INVESTMENT BASE	\$ 12,721,599	From Worksheet 1
x Cost of Capital Rate	0.0800000	
= Investment Return and Income Taxes	<u>1,017,728</u>	To Worksheet 1

Norwood Municipal Light Department

Calendar Year 2011

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Mass DTE AR Reference for col (1)
<u>Transmission Plant</u>						
1	\$ 15,910,580		15,910,580		15,910,580	Line 1, Worksheet 5
2	4,574,504	8.4651% (a)	387,236	65.1447%	252,264	Page 8B line 29(g)
3			16,297,816		16,162,844	
4	0		0	65.1447%	0	None known
<u>Transmission Accumulated Depreciation</u>						
5	5,228,877		5,228,877	65.1447%	3,406,336	Page 8A, line 31(g) less Page 16, line 31(g)
6	1,301,606	8.4651% (a)	110,182	65.1447%	71,778	Page 8B, line 29(g) less Page 17, line 29(g)
7			5,339,059		3,478,114	
<u>Transmission Accumulated Deferred Taxes</u>						
8	0	34.1643% (c)	0	65.1447%	0	None known
9	0	34.1643% (c)	0	65.1447%	0	None known
10			0		0	
11	0	34.1643% (c)	0	65.1447%	0	None known
<u>Other Regulatory Assets</u>						
12	0	8.4651% (a)	0	65.1447%	0	None known
13	0	34.1643% (c)	0	65.1447%	0	None known
14	0	34.1643% (c)	0	65.1447%	0	
15			0		0	
16	36,938	8.4651% (a)	3,127	65.1447%	2,037	Assumed none
17	0		0	65.1447%	0	Assumed none
<u>Cash Working Capital</u>						
19					109,467	Worksheet 1, Line 20
20					169,189	Worksheet 1, Line 21
21					0	Worksheet 1, Line 24
22					278,656	
23					0.125	x 45 / 360
24					34,832	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

Norwood Municipal Light Department

Calendar Year 2011

		(2)	(4)			
Shading denotes an input						
Line No.	(1) Total	Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Mass DTE AR Reference for col (1)
<u>Depreciation Expense</u>						
1	608,361		608,361	65.1447%	396,315	Page 16, line 31(d)
2	124,272	8.4651% (a)	10,520	65.1447%	6,853	Page 17, line 29(d)
3	Total (line 1+2)		618,881		403,168	
<u>Amortization of Loss on Reacquired Debt</u>						
4	0	34.1643% (c)	0	65.1447%	0	None known
<u>Amortization of Investment Tax Credits</u>						
5	0	34.1643% (c)	0	65.1447%	0	None known
<u>Property Taxes *</u>						
6	1,100,000 (d)	100.0000%	1,100,000	84.7697%	932,467	DTE, p. 21 line 24
7	0	2.2482% (a)	0	84.7697%	0	DTE, p. 21 line 24
8	Total (line 6+7)		1,100,000		932,467	
<u>Transmission Operation and Maintenance</u>						
9	1,928,593		1,928,593	0.651447	1,256,376	Page 40, line 50(b)
10	1,418,425		1,418,425	0.651447	924,029	Page 40, line 38(b)
11	178,706		178,706	0.651447	116,417	Page 40, line 34(b)
12	**Station Expenses & Rents - #562 / #567		163,425	0.651447	106,463	Page 40, line 35(b) 40(b)
13	O&M less lines 10, 11 & 12		331,462	65.1447%	109,467	
<u>Transmission Administrative and General</u>						
14	Administrative and General					Page 42, line 6(b)
15	less Property Insurance (#924)					Page 41, line 47(b)
16	less Regulatory Commission Expenses (#928)					Page 41, line 50(b)
17	less General Advertising Expense (#930.1)					assumed none
18	Subtotal [line 14 minus (15 thru 17)]	8.4651% (a)	211,261	65.1447%	137,625	
19	PLUS Property Insurance alloc. using Plant Allocation	34.1643% (c)	48,452	65.1447%	31,564	
20	PLUS Regulatory Comm. Exp. (FERC Assessments)	34.1643% (c)	0	65.1447%	0	
21	PLUS Trans. Related General Advertising Expense	34.1643% (c)	0	65.1447%	0	
22	Total A&G [line 18 plus (19 thru 21)]		259,713		169,189	
23	Payroll Tax Expense	8.4651% (a)	32,389	65.1447%	21,100	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

(d) Property Taxes are for Transmission Related Plant only

Shading denotes an input

Calendar Year 2011

Line No.			Mass DTE AR Reference
	<u>PTF Transmission Plant Allocation Factor</u>	Norwood	
1	PTF Transmission Investment	15,910,580	See Worksheet
2	Total Transmission Investment	24,423,437	Page 8A, line 31(g)
3	Percent Allocation (Line 1/Line 2)	65.1447%	
	<u>Transmission Wages and Salaries Allocation Factor</u>		
4	Direct Transmission Wages and Salaries	258,256	See Worksheet
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 & 6a of 8
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	258,256	
7	Total Wages and Salaries	3,478,355	Page 42, line 24 (c)
8	Administrative and General Wages and Salaries	427,534	Page 41, line 43(b)
9	Affiliated Company Wages and Salaries less A&G	0	Worksheet 6 & 6a of 8
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	3,050,821	
11	Percent Allocation (Line 6/Line 10)	8.4651%	
	<u>Plant Allocation Factor</u>		
12	Total Transmission Investment	24,423,437	Line 2
13	<i>plus Transmission-Related General Plant (Line 2 of Wkst. 3)</i>	387,236	Worksheet 3, Line 2
14	<i>= Revised Numerator (Line 12 + Line 13)</i>	24,810,673	
15	Total Plant in Service	72,621,647	Page 8B, line 30 (g)
16	Percent Allocation (Line 14 / Line 15)	34.1643%	

Affiliated Company Wages and Salaries

 Shading denotes an input

Calendar Year 2011

<u>Line</u>		<u>Norwood</u>
"Affiliated" Transmission Wages and Salaries #560 - 573		
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11 = 1 thru 10	Total Transmission	0
12 = Total "Affiliated" Wages and Salaries		0
Less "Affiliated" Administrative and General Salaries #920 - 935		
13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
21 = 13 thru 20		0
22 = 12 less 21	Total "Affiliated" less A&G	0

NORWOOD

PTF Revenue Requirements

Sheet: Worksheet 7

Calendar Year 2011

Worksheet 7 of 7

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	FERC Form 1	TOTAL	
			Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	332.(g); [332.1(g) for HWP]		0
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			0
	Comerford 115 kV Substation			
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	332.1(g); [332(g) for CL&P]		0
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 394 line	332(g)		
	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			0
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310 line	330.1(n)		
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
Total =			0	0

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

NSTAR Electric Company

Sheet: Input Panel

Input Panel

Regional Network Service
Annual Transmission Revenue Requirements
per Attachment F of the ISO New England Inc. Open Access Transmission Tariff

Shading denotes an input

Submitted on:	<u>5/9/2012</u>
Revenue Requirements for (year):	<u>2011</u>
Customer:	<u>NSTAR Electric Company</u>
Customer's NABs Number:	<u>3</u>
Name of Participant responsible for customer's billing:	<u>NSTAR Electric Company</u>
DUNS number of Participant responsible for customer's billing:	<u>6951552</u>

	<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>
Total of Attachment F - Sections A through I =	<u>52,068,297</u> (a)	<u>107,833,360</u> (f)
Total of Attachment F - Section J - Support Revenue	<u>(454,135)</u> (b)	<u>-</u> (g)
Total of Attachment F - Section K - Support Expense	<u>1,447,034</u> (c)	<u>-</u> (h)
Total of Attachment F - Section L through O	<u>(137,591)</u> (d)	<u>(277,578)</u> (i)
Sub Total - Sum (A through I) - J + K + (L through O)	<u>52,923,604</u> (e)=(a)-(b)+(c)+(d)	<u>107,555,781</u> (j)=(f)-(g)+(h)+(i)
Forecasted Incremental Transmission Revenue Requirements	- n/a	12,060,057 (m)
Annual True-up	(1,469,020) (k)	1,850,100 (n)
Interest Charge on Annual True-up	(48,953) (l)	61,652 (o)
Total = (e) + (j) + (k) + (l) + (m) + (n) + (o)	51,405,632 (p)	121,527,590 (q)
Annual Projected 2010 Revenue Requirement Total = Sum of Pre-97 Revenue Requirements, plus Post-96 Revenue Requirements, plus Annual True-up, and plus Interest on Annual True-up:		<u><u>\$ 172,933,222</u></u> (r) = (p)+(q)

Input Panel

NSTAR Electric Company
Annual Revenue Requirements of pre-1997 & post-1996 PTF
for costs in 2011 06/11-05/12

Line No.	I. INVESTMENT BASE	Attachment F Reference	Pre 1997	Post 1996	Reference
		Section:			
1	Transmission Plant	II (A)(1)(a)	\$ 390,095,759	\$ 786,983,071	Page 4, line 2
2	General Plant	II (A)(1)(b)	3,371,088	6,800,866	Page 4, line 3
3	Plant Held For Future Use	II (A)(1)(c)	-	798,633	Page 4, line 5
4	Total Plant		<u>\$ 393,466,847</u>	<u>\$ 794,582,570</u>	Sum Lines 1 thru 3
5	Accumulated Depreciation	II (A)(1)(d)	(105,893,808)	(213,631,212)	Page 4, line 9
6	Accumulated Deferred Income Taxes	II (A)(1)(e)	(95,343,086)	(192,346,082)	Page 4, line 14
7	Loss On Reacquired Debt	II (A)(1)(f)	1,260,769	2,543,488	Page 4, line 15
8	Other Regulatory Assets	II (A)(1)(g)	<u>3,402,232</u>	<u>6,863,696</u>	Page 4, line 20
9	Net Investment		<u>\$ 196,892,954</u>	<u>\$ 398,012,459</u>	Sum Lines 4 thru 8
10	Prepayments	II (A)(1)(h)	104,527	210,874	Page 4, line 21
11	Materials & Supplies	II (A)(1)(i)	896,133	1,807,868	Page 4, line 22
12	Cash Working Capital	II (A)(1)(j)	<u>1,274,233</u>	<u>2,320,265</u>	Page 4, line 29
13	Total Investment Base		<u><u>\$ 199,167,847</u></u>	<u><u>\$ 402,351,466</u></u>	Sum Lines 9 thru 12
II. REVENUE REQUIREMENTS					
14	Investment Return and Income Taxes	II (A)	\$ 26,518,911	\$ 56,289,779	Page 3, Line 26
15	Depreciation Expense	II (B)	9,080,955	18,320,009	Page 5, Line 4
16	Amortization of Loss on Reacquired Debt	II (C)	178,846	360,807	Page 5, Line 5
17	Investment Tax Credit	II (D)	(96,126)	(193,925)	Page 5, Line 6
18	Property Taxes	II (E)	6,985,890	14,093,403	Page 5, Line 8
19	Payroll Tax Expense	II (F)	198,854	401,170	Page 5, Line 24
20	Operation & Maintenance Expense	II (G)	6,437,737	12,987,553	Page 5, Line 14
21	Administrative & General Expense	II (H)	2,763,229	5,574,564	Page 5, Line 23
22	Transmission Related Integrated Facilities Charge	II (I)	-	-	
23	Transmission Support Revenue	II (J)	(454,135)	-	Page 7, Line 13
24	Transmission Support Expense	II (K)	1,447,034	-	Page 7, Line 13
25	Transmission Related Expense from Generators	II (L)	-	-	
26	Transmission Related Taxes and Fees Charge	II (M)	-	-	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	II (N)	(137,591)	(277,578)	OATT Schedule 8 TOUT
28	Transmission Rents Received from Electric Property	II (O)	-	-	
29	Total Revenue Requirements		<u><u>\$ 52,923,604</u></u>	<u><u>\$ 107,555,781</u></u>	Sum Lines 14 thru 28
III. CURRENT CALENDAR YEAR ESTIMATED INCREMENTAL REVENUE REQUIREMENT					
30	Carrying Charge Factor Base Revenue Requirement Numerator			\$ 107,833,360	Line 29 - Line 27
31	Post-2003 Enhanced Return Addition to Revenue Requirement			-	
32	Total Post-96 PTF Revenue Requirement			<u>\$ 107,833,360</u>	Sum Lines 30 thru 31
33	Post-96 PTF Transmission Plant in Service			\$ 786,983,071	Line 1
34	Post-96 Carrying Charge Factor (Post-96 CCF)			0.137021193	Line 32 / Line 33
35	Forecasted Post-96 PTF Plant Additions			\$ 88,016,000	
36	Forecasted Post-96 Localized PTF Plant Additions			-	
37	Forecasted Post-96 Pool-Supported PTF Plant Additions			<u>88,016,000</u>	Sum Lines 35 thru 36
38	Post-96 Estimated Incremental Revenue Requirement			<u><u>\$ 12,060,057</u></u>	Line 34 * Line 37

NSTAR Electric Company
FERC Interest Calculation associated with Under / (Over)
True-up and Interest Calculation 06/11-05/12

				<u>Pre'97</u>	<u>Post'96</u>	
1	2011 Est. Transmission Revenue Requirements (as billed)	6/11-05/12	Appendix C	54,392,624	105,705,682	ATRR - Prior Year
2	2011 Actual Annual RR			52,923,604	107,555,781	Input Panel Subtotals
3	True-up Over/(Under) (Line 1 - Line 2)			1,469,020	(1,850,100)	

	(Overcollection)/Undercollection	
Pre'97	(\$1,469,020)	- Line 3 Pre '97
Post'96	\$1,850,100	- Line 3 Post '96

Initial Billing Period	Pre 1997 Balance	Post 1996 Balance	FERC Monthly Interest Rate	Pre 1997 Interest	Post 1996 Interest
June 2011	\$ (1,469,020)	\$ 1,850,100	0.27%	\$ (3,966)	\$ 4,995
July 2011	(1,472,986)	1,855,095	0.27%	(3,977)	5,009
August 2011	(1,472,986)	1,855,095	0.28%	(4,124)	5,194
September 2011	(1,472,986)	1,855,095	0.27%	(3,977)	5,009
October 2011	(1,485,064)	1,870,307	0.28%	(4,158)	5,237
November 2011	(1,485,064)	1,870,307	0.27%	(4,010)	5,050
December 2011	(1,485,064)	1,870,307	0.28%	(4,158)	5,237
January 2012	(1,497,390)	1,885,830	0.28%	(4,193)	5,280
February 2012	(1,497,390)	1,885,830	0.26%	(3,893)	4,903
March 2012	(1,497,390)	1,885,830	0.28%	(4,193)	5,280
April 2012	(1,509,669)	1,901,294	0.27%	(4,076)	5,133
May 2012	(1,509,669)	1,901,294	0.28%	(4,227)	5,324
	Total Interest			\$ (48,953)	\$ 61,652
	True-Up			(1,469,020)	1,850,100
	Total TU & Int			\$ (1,517,972)	\$ 1,911,751

NSTAR Electric Company 2012 Forecasted PTF Transmission Revenue Requirements
(in thousands)

Company	Project Name	RSP ID	(A)	(B)	(C)=(A)x(B)	(D)	(E)=[(C)*1000] / (D)
			Estimated PTF Plant In-Service (in thousands)	Annual Carrying Charge	Forecasted PTF Revenue Requirement (in thousands)	2011 12CP RNS Load (kW)	RNS Rate Impact \$/kw-yr
NSTAR	Upgrade Line 322 (condition project)	1191	\$ 17,034	13.70%	\$ 2,334		
NSTAR	BPS Program Waltham Upgrade	1065	\$ 9,753	13.70%	\$ 1,336		
NSTAR	423-515 2nd leg	840	\$ 4,603	13.70%	\$ 631		
NSTAR	Rebuild 201-501 & 201-502 lines	1175	\$ 3,156	13.70%	\$ 432		
NSTAR	NEEWS- Interstate Proj Upgrade Line 336	1202	\$ 1,848	13.70%	\$ 253		
NSTAR	Brook St Transf Addition	1345	\$ 1,724	13.70%	\$ 236		
NSTAR	Hartwell Ave 115 kV Cap bank	1198	\$ 1,300	13.70%	\$ 178		
NSTAR	Lexington-Waltham 115kV Lines (Reconductor 115kV Line 320-507/508)	301	\$ 824	13.70%	\$ 113		
NSTAR	BPS Program Needham Upgrade	1066	\$ 235	13.70%	\$ 32		
NSTAR	Chelsea Cap bank	969	\$ 146	13.70%	\$ 20		
NSTAR	128-518 reconductoring (115kV Line Chelsea-Revere)	1201	\$ 60	13.70%	\$ 8		
NSTAR	K St Breaker and Tie Bus	1113	\$ 32	13.70%	\$ 4		
NSTAR	Subtotal RSP Projects		\$ 40,715		\$ 5,579		
NSTAR	Replace New Line 324		\$ 7,212	13.70%	\$ 988		
NSTAR	Medway 345A 2011/2012(install)		\$ 6,052	13.70%	\$ 829		
NSTAR	Structure Replacements - Line 331		\$ 5,465	13.70%	\$ 749		
NSTAR	Structure Replacements - Line 108		\$ 3,458	13.70%	\$ 474		
NSTAR	Structure Replacements - Line 3361		\$ 3,458	13.70%	\$ 474		
NSTAR	Structure Replacements - Line 336		\$ 3,458	13.70%	\$ 474		
NSTAR	Replace Portion of 21 115kV Breakers at various substations-West		\$ 1,742	13.70%	\$ 239		
NSTAR	Security System Upgrades		\$ 1,320	13.70%	\$ 181		
NSTAR	Static Wire Replacement		\$ 1,307	13.70%	\$ 179		
NSTAR	ROW Roads		\$ 1,188	13.70%	\$ 163		
NSTAR	BPS Support- NSTAR terminals Line 323, 357		\$ 1,104	13.70%	\$ 151		
NSTAR	Replace (8) 115kV Breakers (STA 110, 211) (Install Only)		\$ 1,032	13.70%	\$ 141		
NSTAR	Counterpoise Replacement		\$ 912	13.70%	\$ 125		
NSTAR	Install DFR Relays		\$ 910	13.70%	\$ 125		
NSTAR	230kV breaker for 282-602 at jet site Sta 446		\$ 779	13.70%	\$ 107		
NSTAR	Polymer Insulator and Lightning Replacement		\$ 705	13.70%	\$ 97		
NSTAR	SEECO Switch Replacement		\$ 624	13.70%	\$ 86		
NSTAR	Static Wire Replacement		\$ 598	13.70%	\$ 82		
NSTAR	Cathodic Protection Program		\$ 545	13.70%	\$ 75		
NSTAR	Replace Heat Exchangers (STA 148, 509, 250, 514)		\$ 520	13.70%	\$ 71		
NSTAR	Replace Transmission Batteries		\$ 445	13.70%	\$ 61		
NSTAR	Replace 10 115kV Disconnects		\$ 427	13.70%	\$ 59		
NSTAR	Replace 1 345kV Breakers at Holbrook (Install only)		\$ 425	13.70%	\$ 58		
NSTAR	Remote Redundancy Pump Plants		\$ 411	13.70%	\$ 56		
NSTAR	Replace 115kV CCVTs at various locations		\$ 380	13.70%	\$ 52		
NSTAR	Replace Portion of 25 115kV Disconnects-Central		\$ 330	13.70%	\$ 45		
NSTAR	Replace 3 345kV Breakers at Carver Install Only		\$ 260	13.70%	\$ 36		
NSTAR	PT CT (STA 447, 150, 509, 478)		\$ 248	13.70%	\$ 34		
NSTAR	PTC Heat Exch - station work		\$ 245	13.70%	\$ 34		
NSTAR	Replace 8 345kV Disconnects Switches - TBD		\$ 226	13.70%	\$ 31		
NSTAR	Install Synchro-phasor upgrades		\$ 215	13.70%	\$ 29		
NSTAR	Cathodic Protection: Replace 12 Anodes Replace 35 P-Cells		\$ 160	13.70%	\$ 22		
NSTAR	Holbrook STA 478 345 Auto Spare		\$ 157	13.70%	\$ 22		
NSTAR	Carver 345A, install in 2011		\$ 152	13.70%	\$ 21		
NSTAR	Replace Portion of 25 115kV Disconnects-South		\$ 138	13.70%	\$ 19		
NSTAR	ROW Gates		\$ 119	13.70%	\$ 16		
NSTAR	Install Portion of 175 Meters at various locations-West		\$ 99	13.70%	\$ 14		
NSTAR	STA 980 Transmission Breaker Repla		\$ 95	13.70%	\$ 13		
NSTAR	Install new DFR at STA 350 & 496, Upgrade DFR's at STA 958, 250		\$ 84	13.70%	\$ 12		
NSTAR	Heat Exchangers & Misc. PP Upgrades		\$ 59	13.70%	\$ 8		
NSTAR	STA 456 TRV Mitigation		\$ 55	13.70%	\$ 8		
NSTAR	SEECO Switches		\$ 52	13.70%	\$ 7		
NSTAR	Structure Replacements		\$ 38	13.70%	\$ 5		
NSTAR	Replace Transmission Batteries-Central		\$ 38	13.70%	\$ 5		
NSTAR	ROW Gates		\$ 34	13.70%	\$ 5		
NSTAR	Replace Portion of 21 115kV Breakers at various substations-Centra		\$ 20	13.70%	\$ 3		
NSTAR	Subtotal: Other Projects		\$ 47,301		\$ 6,481		
Total NSTAR			\$ 88,016		\$ 12,060	20,178,343	\$ 0.59767

ISO New England Inc.
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 per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3
 NSTAR Electric Company
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Submitted on:	<u>May 9, 2012</u>
Revenue Requirements for (year):	<u>2011</u>
Customer:	<u>NSTAR Electric Company</u>
Customer's NABs Number:	<u>3</u>
Name of Participant responsible for customer's billing:	<u>NSTAR Electric Company</u>
DUNS number of Participant responsible for customer's billing:	<u>6951552</u>

	<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>
Total of Attachment F - Sections A through I	= \$ <u>52,068,297</u> (a)	\$ <u>107,833,360</u> (f)
Total of Attachment F - Section J - Support Revenue	= <u>454,135</u> (b)	<u>-</u> (g)
Total of Attachment F - Section K - Support Expense	= <u>1,447,034</u> (c)	<u>-</u> (h)
Total of Attachment F - Sections L-O	= <u>(137,591)</u> (d)	<u>(277,578)</u> (i)
Sub Total - Sum (A through H) - J + K+ (L through O)	= <u>\$ 52,923,604</u> (e)=(a)-(b)+(c)+(d)	\$ <u>107,555,781</u> (j)
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:		\$ <u>160,479,386</u> (k) = (e) + (j)

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Line	Investment Base	Attachment F Reference	Pre-1997	Post-1996	Reference
		Section:			
	Col.A	Col.B	Col.C	Col.D	Col.E
1	Transmission Plant	II (A)(1)(a)	\$ 390,095,759	\$ 786,983,071	Page 4, line 2
2	General Plant	II (A)(1)(b)	3,371,088	6,800,866	Page 4, line 3
3	Plant Held For Future Use	II (A)(1)(c)	-	798,633	Page 4, line 5
4	Total Plant		393,466,847	794,582,570	Sum Lines 1 thru 3
5	Accumulated Depreciation	II (A)(1)(d)	(105,893,808)	(213,631,212)	Page 4, line 9
6	Accumulated Deferred Income Taxes	II (A)(1)(e)	(95,343,086)	(192,346,082)	Page 4, line 14
7	Loss On Reacquired Debt	II (A)(1)(f)	1,260,769	2,543,488	Page 4, line 15
8	Other Regulatory Asssets	II (A)(1)(g)	3,402,232	6,863,696	Page 4, line 20
9	Net Investment		196,892,954	398,012,459	Sum Lines 4 thru 8
10	Prepayments	II (A)(1)(h)	104,527	210,874	Page 4, line 21
11	Materials & Supplies	II (A)(1)(II)	896,133	1,807,868	Page 4, line 22
12	Cash Working Capital	II (A)(1)(j)	1,274,233	2,320,265	Page 4, line 29
13	Total Investment Base		\$ 199,167,847	\$ 402,351,466	Sum Lines 9 thru 12
14	Revenue Requirement				
15	Investment Return and Income Taxes	II (A)	\$ 26,518,911	\$ 56,289,779	Page 3, Line 26
16	Depreciation Expense	II (B)	9,080,955	18,320,009	Page 5, Line 4
17	Amortization of Loss on Reacquired Debt	II (C)	178,846	360,807	Page 5, Line 5
18	Investment Tax Credit	II (D)	(96,126)	(193,925)	Page 5, Line 6
19	Property Taxes	II (E)	6,985,890	14,093,403	Page 5, Line 8
20	Payroll tax Expense	II (F)	198,854	401,170	Page 5, Line 27
21	Operation & Maintenance Expense	II (G)	6,437,737	12,987,553	Page 5, Line 14
22	Administrative & General Expense	II (H)	2,763,229	5,574,564	Page 5, Line 26
23	Transmission Related Integrated Facilities Charge	II (I)	-	-	
24	Transmission Support Revenue	II (J)	(454,135)	-	Page 7, Line 13
25	Transmission Support Expense	II (K)	1,447,034	-	Page 7, Line 13
26	Transmission Related Expense from Generators	II (L)	-	-	
27	Transmission Related Taxes and Fees Charge	II (M)	-	-	
28	Revenue for ST Trans Service Under NEPOOL Tariff	II (N)	(137,591)	(277,578)	OATT Schedule 8 TOUT
29	Transmission Rents Received for Electric Property	II (O)	-	-	
30	Total Revenue Requirements		\$ 52,923,604	\$ 107,555,781	Sum Lines 15 thru 29
31	Total			\$ 160,479,386	Sum Line 30, Col C & Col D

ISO New England Inc.
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NSTAR Electric Company
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Line	Description	Capitalization 12/31/11	Cost of Capital	Weighted Cost of Capital	Weighted Equity Portion
	Col.A	Col.B	Col.C	Col.D	Col.E
1	Long-Term Debt	\$ 1,595,344,024	5.3821%	2.2189%	
2	Preferred Stock	43,000,000	4.5581%	0.0507%	0.0507%
3	Common Equity	2,231,342,641	11.6400%	<u>6.7119%</u>	<u>6.7119%</u>
4	Total Investment Return	\$ 3,869,686,665		<u>8.9814%</u>	<u>6.7625%</u>
ROE per ISO New England Inc. Transmission, Markets and Services Tariff, Section II Attachment F II.A.2.(iii), page 231 http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/sect_ii.pdf					
5	Federal Income Tax (FIT)	Pre-97	Post 96		
6	A= Preferred & Equity Return	6.76252%	6.76252%	Preferred & Equity Return	
7	B= Transmission Related Amortization of ITC	\$ (96,126)	\$ (193,925)	Page 2, Line 18	
8	C= Equity AFUDC Component of Depreciation Expense	\$ -	\$ -	Equity AFUDC Component of Tramssion Dep Exp	
9	D= Transmission Investment Base	\$ 199,167,847	\$ 402,351,466	Page 2, Line 13	
10	FT = Federal Income Tax Rate	35%	35%	Federal Income Tax Rate	
11	FIT = (A+[C+B]/D)/(FT)/(1-FT)	3.61537%	3.61540%	Federal Income Tax	
12	ST = State Income Tax Rate	6.50%	6.50%	State Tax Rate	
13	State IncomeTax (SIT)				
14	SIT = (A+[(C+B)/D]+Federal Income Tax)(ST)/(1-ST)	0.71810%	0.71811%	State IncomeTax	
15	Allowed Return	13.31486%	13.31490%	line 4, Col.D + Line 11 + Line 14	
16	D= Transmission Investment Base	\$ 199,167,847	\$ 402,351,466	Page 2, Line 13	
17	Return	\$ 26,518,911	\$ 53,572,688	Line 15 * Line 16	
18	Incremental return for Post 2003 PTF Investment				
19	A= Incremental Return		1%	Incremental return on Equity Component	
20	Effective Incremental (a')		0.57662%	line 19 * line 3 / line 4	
21	Additional FIT (a'/A')		0.31049%	Incremental FIT = (a' x FT)/(1-FT)	
22	Additional SIT (a'/A')		0.06167%	Incremental SIT = (A' + FIT)(ST)/(1-ST)	
23	Additional Return		0.94878%	Sum lines 20 thru 22	
24	Post 2003 PTF net Investment		\$ 286,377,360	Page 8, line 16	
25	Additional 100 bp Return Post 2003 PTF Investment		\$ 2,717,091	Line 23 * Line 24	
26	Total Return	\$ 26,518,911	\$ 56,289,779	Line 17 + Line 25	
		Capitalization 12/31/11	Cost of Capital	Weighted Cost of Capital	Weighted Equity Portion
27	Incremental return for PTF 50 Basis Point Adder				
28	Long-Term Debt	\$ 1,595,344,024	5.3821%	2.2189%	
29	Preferred Stock	43,000,000	4.5581%	0.0507%	
30	Common Equity	2,231,342,641	0.5000%	<u>0.2883%</u>	<u>0.2883%</u>
31	Total Investment Return	\$ 3,869,686,665		<u>2.5578%</u>	<u>0.2883%</u>
32	Federal Income Tax (FIT)	Pre-97	Post 96		
33	A= Incremental Return	0.28831%	0.28831%	Equity Return	
34	B= Transmission Related Amortization of ITC	\$ (96,126)	\$ (193,925)	Page 2, Line 18	
35	C= Equity AFUDC Component of Depreciation Expense	\$ -	\$ -	Equity AFUDC Component of Tramssion Dep Exp	
36	D= Transmission Investment Base	\$ 199,167,847	\$ 402,351,466	Page 2, Line 13	
37	FT = Federal Income Tax Rate	35%	35%	Federal Income Tax Rate	
38	FIT = (A+[C+B]/D)/(FT)/(1-FT)	0.12926%	0.12929%	Federal Income Tax	
39	ST = State Income Tax Rate	6.50%	6.50%	State Tax Rate	
40	State IncomeTax (SIT)				
41	SIT = (A+[(C+B)/D]+Federal Income Tax)(ST)/(1-ST)	0.02567%	0.02568%	State IncomeTax	
42	Allowed Return	0.44324%	0.44328%	line 33 + Line 38 + Line 41	
43	D= Transmission Investment Base	\$ 199,167,847	\$ 402,351,466	Page 2, Line 13	
44	Return 50 bp Adder	\$ 882,791	\$ 1,783,553	Line 42 * Line 43	
45	Total Return 50 bp Adder		\$ 2,666,344	Line 44 Pre-97 + Line 44 Post 96	
46	Total Incremental Return		\$ 5,383,435	Line 25 + Line 45	

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Line	Description	Total	Allocation Factors Wage/Plant Col.C	Transmission Allocated Col.D (Col.B x Col.C)	Pre-97 PTF		Post-96 PTF		FERC Form 1 Reference for Col. B
					Allocation Factor (b) Pre-97 PTF Col.E	Pre-97 PTF Allocated Col.F (Col.B x Col.E)	Allocation Factor (b) Post 96 PTF Col.G	Post 96 PTF Allocated Col.H (Col.D x Col.G)	
	Col.A	Col.B							Col.I
1	Transmission Plant								
2	Transmission Plant (exc SCADA)	\$ 1,375,635,652		\$1,375,635,652		\$ 390,095,759		\$ 786,983,071	Page 6, Line 3
3	General Plant	181,870,260	6.5364%	(a) <u>11,887,818</u>	28.3575%	<u>3,371,088</u>	57.2087%	<u>6,800,866</u>	FF1 207.99g
4	Total Transmission Plant			<u>\$1,387,523,469</u>		<u>\$ 393,466,847</u>		<u>\$ 793,783,937</u>	Sum line 2 thru line 3
5	Transmission Plant Held for Future Use	\$ 798,633	100.0000%	\$ 798,633	0.0000%	-	100.0000%	\$ 798,633	FF1 214.13d+14d+15d
6	Transmission Accumulated Depreciation								
7	Transmission Accum. Depreciation (exc SCADA)	\$ (369,363,766)		\$ (369,363,766)	28.3575%	\$ (104,742,330)	57.2087%	\$ (211,308,209)	Page 8, Line 11
8	General Plant Accum.Depreciation	(62,122,279)	6.5364%	(a) <u>(4,060,578)</u>	28.3575%	<u>(1,151,478)</u>	57.2087%	<u>(2,323,004)</u>	FF1 219.28b
9	Total Transmission Acc Dep			<u>\$ (373,424,343)</u>		<u>\$ (105,893,808)</u>		<u>\$ (213,631,212)</u>	Sum line 7 thru line 8
10	Transmission Accumulated Deferred Taxes								
11	Accumulated Deferred Taxes (282) (d)	\$ (851,411,783)	24.4683%	(c) \$ (208,325,884)	28.3575%	\$ (59,076,012)	57.2087%	\$ (119,180,530)	Line 35
12	Accumulated Deferred Taxes (283) (e)	(583,066,335)	24.4683%	(c) (142,666,348)	28.3575%	(40,456,610)	57.2087%	(81,617,563)	Line 38
13	Accumulated Deferred Taxes (190)	60,380,173	24.4683%	(c) <u>14,773,994</u>	28.3575%	<u>4,189,535</u>	57.2087%	<u>8,452,010</u>	FF1 234.18c
14	Total			<u>\$ (336,218,237)</u>		<u>\$ (95,343,086)</u>		<u>\$ (192,346,082)</u>	Sum line 11 thru line 13
15	Transmission loss on Reacquired Debt	\$ 18,170,384	24.4683%	(c) \$ 4,445,982	28.3575%	\$ 1,260,769	57.2087%	\$ 2,543,488	FF1 111.81c
16	Other Regulatory Assets								
17	FAS 106	\$ 773,258	6.5364%	(a) \$ 50,543					FF1 232.1.30f
18	ASC 740 Regulatory Asset (FAS 109)	54,832,155	24.4683%	(c) 13,416,489					FF1 232.1.20f
19	ASC 740 Regulatory Liability (FAS 109)	<u>(6,005,283)</u>	24.4683%	(c) <u>(1,469,390)</u>					FF1 278.2f
20	Total	<u>\$ 49,600,130</u>		<u>\$ 11,997,643</u>	28.3575%	<u>\$ 3,402,232</u>	57.2087%	<u>\$ 6,863,696</u>	Sum line 17 thru line 19
21	Transmission Prepayments	\$ 5,639,239	6.5364%	(a) \$ 368,605	28.3575%	\$ 104,527	57.2087%	\$ 210,874	FF1 111.57c
22	Transmission Materials and Supplies	\$ 3,160,128	100.0000%	\$ 3,160,128	28.3575%	\$ 896,133	57.2087%	\$ 1,807,868	FF1 227.8c + 5c(footnote)
23	Cash Working Capital								
24	Operation & Maintenance Expense					\$ 6,437,737		\$ 12,987,553	Page 5, line 14
25	Administrative & General Expense					2,763,229		5,574,564	Page 5, line 26
26	Transmission Support Expense					<u>992,899</u>		-	Page 7, line 14
27	Total					<u>\$ 10,193,864</u>		<u>\$ 18,562,117</u>	Sum line 24 thru line 26
28	45 day rule					<u>0.125</u>		<u>0.125</u>	= 45 / 360
29	Cash Working Capital					<u>\$ 1,274,233</u>		<u>\$ 2,320,265</u>	Line 27 * line 28
30	(a) Labor Allocator Page 6, Line 14	6.5364%							
31	(b) PTF Allocator Page 6, Line 4				28.3575%		57.2087%		
32	(c) Plant Allocator Page 6, Line 20	24.4683%							
33	(d) Account 282	\$ 851,411,783		FF1 275.9k					
34	less amounts related to divestiture	-		FF1 275.4k					
35	Total Account 282	<u>\$ 851,411,783</u>		Sum line 33 thru line 34					
36	(e) Account 283	\$ 624,400,051		FF1 277.9k					
37	less amounts related to divestiture	<u>(41,333,716)</u>		FF1 277.9k(footnote)					
38	Total Account 283	<u>\$ 583,066,335</u>		Sum line 36 thru line 37					

ISO New England Inc.
FERC Electric Tariff No. 3
Open Access Transmission Tariff
Section II - Attachment F Implementation Rule
per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3
NSTAR Electric Company
Page 5

Shading denotes an input

Line	Description	Total	Wage/Plant Allocation Factors	Transmission Allocated	Pre-97 PTF		Post 96 PTF		Reference for Col. B FF1 = FERC Form 1
					Allocation Factor (b)	Pre-97 PTF Allocated	Allocation Factor (b)	Post 96 PTF Allocated	
	Col.A	Col.B	Col.C	Col.D (Col.B x Col.C)	Col.E	Col.F (Col.D x Col.E)	Col.G	Col.H (Col.D x Col.G)	Col.I
1	<u>Depreciation Expense</u>								
2	Transmission Depreciation	\$ 31,448,396		\$ 31,448,396	28.3575%	\$ 8,917,979	57.2087%	\$ 17,991,218	Page 8, Line 11, Col.D
3	General Depreciation	<u>8,792,591</u>	6.5364% (a)	<u>574,721</u>	28.3575%	<u>162,977</u>	57.2087%	<u>328,791</u>	FF1 336.10f
4	Total	<u>\$ 40,240,987</u>		<u>\$ 32,023,117</u>		<u>\$ 9,080,955</u>		<u>\$ 18,320,009</u>	Sum line 2 thru line 3
5	<u>Amortization of Loss on Reacquired Debt</u>	\$ 2,577,562	24.4683% (c)	\$ 630,685	28.3575%	\$ 178,846	57.2087%	\$ 360,807	FF1 117.64c
6	<u>Amortization of Investment Tax Credits</u>	\$ 1,385,383	24.4683% (c)	\$ 338,979	28.3575%	\$ 96,126	57.2087%	\$ 193,925	FF1 266.8f & 11f
7	<u>Property Taxes</u>								
8	Transmission Property Taxes	\$ 100,681,628	24.4683% (c)	\$ 24,635,070	28.3575%	\$ 6,985,890	57.2087%	\$ 14,093,403	FF1 263.5i
9	<u>Transmission Operation and Maintenance</u>								
10	Operation and Maintenance	\$ 282,101,634		\$282,101,634	28.3575%	\$ 79,996,971	57.2087%	\$ 161,386,677	FF1 321.112b
11	less: Transmission of Electricity by Others - #565	(237,634,843)		(237,634,843)	28.3575%	(67,387,301)	57.2087%	(135,947,804)	FF1 321.96b
12	less: Load Dispatching - #561 to #561.4	(13,623,124)		(13,623,124)	28.3575%	(3,863,177)	57.2087%	(7,793,612)	FF1 321.85b-.88b
13	less: Rents - #567	(8,141,607)		(8,141,607)	28.3575%	(2,308,756)	57.2087%	(4,657,708)	FF1 321.98b
14	O&M for RNS Tariff	<u>\$ 22,702,060</u>		<u>\$ 22,702,060</u>		<u>\$ 6,437,737</u>		<u>\$ 12,987,553</u>	Sum line 10 thru line 13
15	<u>Transmission Administrative and General</u>								
16	Administrative and General	\$ 151,807,508							FF1 323.197b
17	less Office Supplies and Expenses (921)	(113,082)							FF1: Page 323.182(b) footnote
18	less Outside Services Employed (923)	(1,273,126)							FF1: Page 323.184(b) footnote
19	less Property Insurance (#924)	(498,584)							FF1 323.185b
20	less Regulatory Commission Expenses (#928)	(8,347,816)							FF1 323.189b
21	less General Advertising Expense (#930.1)	<u>(594,986)</u>							FF1 323.191b
22	Subtotal	\$ 140,979,914	6.5364% (a)	\$ 9,215,050	28.3575%	\$ 2,613,158	57.2087%	\$ 5,271,810	Sum line 16 thru line 21
23	Plus Property Ins. alloc. Using Plant Allocator	498,584	24.4683% (c)	121,995	28.3575%	34,595	57.2087%	69,792	Line 19
24	Plus Regulatory Comm. Exp (Transmission FERC Assessments)	1,664,253	24.4683% (c)	407,214	28.3575%	115,476	57.2087%	232,962	FF1 350.8d
25	Plus General Advertising Expense	-	0.0000%	-	28.3575%	-	57.2087%	-	
26	Total A&G for RNS Tariff	<u>\$ 143,142,751</u>		<u>\$ 9,744,259</u>		<u>\$ 2,763,229</u>		<u>\$ 5,574,564</u>	Sum line 22 thru line 25
27	<u>Payroll Tax Expense</u>	<u>\$ 10,728,162</u>	6.5364% (a)	\$ 701,239	28.3575%	<u>\$ 198,854</u>	57.2087%	<u>\$ 401,170</u>	FF1 263.8i
28	(a) Labor Allocator Page 6, Line 14	6.5364%							
29	(b) PTF Allocator Page 6, Line 4				28.3575%		57.2087%		
30	(c) Plant Allocator Page 6, Line 20	24.4683%							

ISO New England Inc.
 FERC Electric Tariff No. 3
 Open Access Transmission Tariff
 Section II - Attachment F Implementation Rule
 per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3
 NSTAR Electric Company
 Page 6

Line	Description	Pre-1997	Post - 1996	Post - 2003	Reference
	Col.A	Col.B	Col.C		Col.D
1	<u>PTF Transmission Plant Allocation Factor</u>				
2	PTF Transmission Investment	\$ 390,095,759	\$ 786,983,071	\$ 468,517,535	Page 8, Col G lines 1,2,3
3	Total Transmission Investment excluding SCADA	\$ 1,375,635,652	\$ 1,375,635,652	\$ 1,375,635,652	Page 8, Line 5, Col.G
4	Percent Allocation	<u>28.3575%</u>	<u>57.2087%</u>	<u>34.0583%</u>	Line 2 / Line 3
5	Total PTF Allocation (Pre 97 + post 96)		<u>85.5662%</u>		Line 4, Col.B plus Col.C
6	<u>Transmission Wages and Salaries Allocation Factor</u>				
7	Direct Transmission Wages and Salaries	\$ 9,972,080			FF1 354.21b
8	Less EMC Transmission Wages and Salaries	<u>(1,912,816)</u>			Acct 561 Labor
9	Total Transmission Wages and Salaries	<u>\$ 8,059,264</u>			Line 7 + Line 8
10	Total Wages and Salaries	\$ 163,696,668			FF1 354.28b
11	Administrative and General Wages and Salaries	(40,398,982)			FF1 354.27b
12	Affiliated Company Wages and Salaries less A&G	-			NA
13	Total Wages and Salaries net of A&G	<u>\$ 123,297,686</u>			Sum lines 10 thru 12
14	Percent Allocation	6.5364%			Line 9 / Line 13
15	<u>Plant Allocation Factor</u>				
16	Total Transmission Investment (exc SCADA)	\$ 1,375,635,652			Line 2
17	Plus Transmission Related General Plant	<u>11,887,818</u>			Page 4, Line 3, Col.D
18	Revised Numerator (Line 12 + Line 13)	<u>\$ 1,387,523,469</u>			Line 16 + Line 17
19	Total Plant in Service	<u>\$ 5,670,701,168</u>			FF1 207.104g
20	Percent Allocation	24.4683%			Line 18 / Line 19
21	Transmission Plant only Allocator	24.2587%			Line 16 / Line 19

ISO New England Inc.
 FERC Electric Tariff No. 3
 Open Access Transmission Tariff
 Section II - Attachment F Implementation Rule
 per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3
 NSTAR Electric Company
 Page 7

Line	PTF Supporting Facilities	Revenues	Expenses	Reference
	Col.B	Col.C	Col.D	
1	National Grid Support Revenues	\$ 4,529		FF1 p.300 line 22 col.(b) footnote
2	Hydro Quebec Phase 2 Support	383,599		FF1 p.300 line 22 col.(b) footnote
3	EUA/NEP Station 342 Support	(6,116)		FF1 p.300 line 22 col.(b) footnote
4	Montaup Station 451 Support	(526)		FF1 p.300 line 22 col.(b) footnote
5	NEP Line 201-502 Medway Support	-		FF1 p.300 line 22 col.(b) footnote
6	Reading Lines 211-503/504 Support	72,649		FF1 p.300 line 22 col.(b) footnote
7	Transmission support revenue	-		FF1 p.300 line 22 col.(b) footnote
8	New England Power Co		13,614	FF1 p.332 line 1 col.(h)
9	Wellesley Municipal Lgt		18,456	FF1 p.332 line 3 col.(h)
10	New England Power Support		5,637	FF1 p.321 line 98 col.(b) footnote
11	Hydro Quebec Phase II NEP AC, Chester SVC		1,370,374	FF1 p.321 line 98 col.(b) footnote
12	Transmission Line Rents		38,953	FF1 p.321 line 98 col.(b) footnote
13	Total	\$ 454,135	\$ 1,447,034	
14	Net		\$ 992,899	

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17 (a) Values for SCADA taken from Schedule 1 Revenue Requirement

Reading Municipal Light Plant

Sheet: Input Panel

Input Panel

Regional Network Service
Annual Transmission Revenue Requirements
per Attachment F of the ISO New England Inc. Open Access Transmission Tariff

 Shading denotes an input

Submitted on: 05/14/2012

Revenue Requirements for (year): 2011

Customer: Reading Municipal Light Plant

Customer's NABs Number: 148

Name of Participant responsible for customer's billing: Bill Seldon

DUNs number of Participant responsible for customer's billing: 86-703-4654

	<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>
Total of Attachment F - Sections A through I =	<u>945</u> (a)	<u>277,971</u> (f)
Total of Attachment F - Section J - Support Revenue	<u>0</u> (b)	<u>0</u> (g)
Total of Attachment F - Section K - Support Expense	<u>94,494</u> (c)	<u>0</u> (h)
Total of Attachment F - Section L through O	<u>0</u> (d)	<u>0</u> (i)
Sub Total - Sum (A through I) - J + K + (L through O)	<u>95,439</u> (e)=(a)-(b)+(c)+(d)	<u>277,971</u> (j)=(f)-(g)+(h)+(i)
Forecasted Incremental Transmission Revenue Requirements		0 (m)
Annual True-up	(142,338)	<u>19,478</u> (n)
Interest Charge on Annual True-up	(4,743)	649 (o)
Total = (e) + (j) + (k) + (l) + (m) + (n) + (o)	(51,642) (p)	298,098 (q)
Annual Projected 2008 Revenue Requirement Total = Sum of Pre-97 Revenue Requirements, plus Post-96 Revenue Requirements, plus Annual True-up, and plus Interest on Annual True-up:		<u><u>246,456</u></u> (r) = (p)+(q)

Reading Municipal Light Plant
Annual Revenue Requirements of pre-1997 & post-1996 PTF
for costs in 2011 and billed 06/11-05/12

RNS Rate

		Attachment F			
		Reference	Pre 1997	Post 1996	Reference
Line No.	I. INVESTMENT BASE	Section:			
1	Transmission Plant	I (A)(1)(a)	0	2,638,470	Worksheet 3, line 1 column 5
2	General Plant	I (A)(1)(b)	0	0	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	I (A)(1)(c)	0	0	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		0	2,638,470	
5	Accumulated Depreciation	I (A)(1)(d)	0	610,262	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	I (A)(1)(e)	0	0	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	I (A)(1)(f)	0	0	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	I (A)(1)(g)	0	0	Worksheet 3, line 15 column 5
9	Net Investment (Line 4-5-6+7+8)		0	2,028,208	
10	Prepayments	I (A)(1)(h)	0	0	Worksheet 3, line 16 column 5
11	Materials & Supplies	I (A)(1)(i)	0	0	Worksheet 3, line 17 column 5
12	Cash Working Capital	I (A)(1)(j)	29,428	1,141	Worksheet 3, line 24 column 5
13	Total Investment Base (Line 9+11+12+13)		13,224	2,029,349	
II. REVENUE REQUIREMENTS					
14	Investment Return and Income Taxes	I (A)	2,354	162,348	Worksheet 2
15	Depreciation Expense	I (B)	0	38,542	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	I (C)	0	0	Worksheet 4, line 4 column 5
17	Investment Tax Credit	I (D)	0	0	Worksheet 4, line 5 column 5
18	Property Taxes	I (E)	0	48,474	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	I (F)	0	0	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	I (G)	0	928	Worksheet 4, line 13 column 5
21	Administrative & General Expense	I (H)	0	8,201	Worksheet 4, line 22 column 5
22	Transmission Related Integrated Facilities Charge	I (I)	0	0	
23	Transmission Support Revenue	I (J)	0	0	Worksheet 7
24	Transmission Support Expense	I (K)	235,423	0	Worksheet 7
25	Transmission Related Expense from Generators	I (L)	0	0	
26	Transmission Related Taxes and Fees Charge	I (M)	0	0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	I (N)	0	0	Txm related Acct 456
28	Transmission Rents Received from Electric Properties	I (O)	0	0	Txm related Acct 454-rent
29	Total Revenue Requirements (Line 14 thru 28)		237,777	258,493	
III. CURRENT CALENDAR YEAR ESTIMATED INCREMENTAL REVENUE REQUIREMENT					
30	Carrying Charge Factor Base Revenue Requirement Numerator			0	
31	Post-2003 Enhanced Return Addition to Revenue Requirement			-	
32	Total Post-96 PTF Revenue Requirement			0	
33	Post-96 PTF Transmission Plant in Service			2,638,470	
34	Post-96 Carrying Charge Factor (Post-96 CCF)			9.5%	
35	Forecasted Post-96 PTF Plant Additions				
36	Forecasted Post-96 Localized PTF Plant Additions			0	
37	Forecasted Post-96 Pool-Supported PTF Plant Additions			0	
38	Post-96 Estimated Incremental Revenue Requirement			0	

RNS Rate

Reading Municipal Light Plant
FERC Interest Calculation associated with Under / (Over)
True Up and Interest Calculation for 2011

1 2011 Actual Annual RR			95,439	277,971	
2 2011 Est. Transmission Revenue Requirements (as billed)	6/11-05/12	Appendix C	237,777	258,493	ATRR - Prior Year
3 True-up (Over)/Under (Line 1 - Line 2)			-142,338	19,478	

Pre'97
Post'96

(Overcollection)/Undercollection

(\$142,338)
\$19,478

Initial Billing Period	Pre 1997 Balance	Post 1996 Balance	FERC Monthly Interest Rate	Pre 1997 Interest	Post 1996 Interest
June 2011	(\$142,338)	\$19,478	0.27%	(\$384)	\$53
July 2011	(142,722)	19,531	0.27%	-385	\$53
August 2011	(142,722)	19,531	0.28%	-400	\$55
September 2011	(142,722)	19,531	0.27%	-385	\$53
October 2011	(143,893)	19,691	0.28%	-403	\$55
November 2011	(143,893)	19,691	0.27%	-389	\$53
December 2011	(143,893)	19,691	0.28%	-403	\$55
January 2012	(145,087)	19,854	0.28%	-406	\$56
February 2012	(145,087)	19,854	0.26%	-377	\$52
March 2012	(145,087)	19,854	0.28%	-406	\$56
April 2012	(146,277)	20,017	0.27%	-395	\$54
May 2012	(146,277)	20,017	0.28%	-410	\$56
		Total Interest		-\$4,743	\$649
		True-Up		-\$142,338	\$19,478
		Total TU & Int		-\$147,081	\$20,127

Sheet: Input Panel

NEPOOL Tariff Billing
NEPOOL Annual Transmission Revenue Requirements
per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3

Shading denotes an input

Submitted on:	<u>14-May-11</u>
Revenue Requirements for (year):	<u>Calendar Year 2011</u>
Customer:	<u>Reading Municipal Light Department</u>
Customer's NABs Number:	<u>148</u>
Name of Participant responsible for customer's billing:	<u>Bill Seldon</u>
DUNS number of Participant responsible for customer's billing:	<u>86-703-4654</u>

		<u>Pre-97 Revenue Requirements</u>		<u>Post-96 Revenue Requirements</u>
Total of Attachment F - Sections A through I	=	<u>945</u> (a)		<u> </u> (f)
Total of Attachment F - Section J - Support Revenue		<u>0</u> (b)		<u>0</u> (g)
Total of Attachment F - Section K - Support Expense		<u>94,494</u> (c)		<u> </u> (h)
Total of Attachment F - Section (L through O)		<u>0</u> (d)		<u>0</u> (i)
Sub Total - Sum (A through I) - J + K + (L through O)		<u>95,439</u> (e)=(a)-(b)+(c)+(d)		<u>0</u> (j)

Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements
and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:

95,439 (k) = (e) + (j)

Total of Attachment F - Section J - Pre-97 Support Revenue (from above)	<u>0</u> (b)
Total of Attachment F - Section J - Post-96 Support Revenue (from above-)	<u>0</u> (g)
Total of Attachment F - Section K - Post-96 Support Expense (from above)	<u>0</u> (h)

Voting Share Total for Participant's R Value: 95,439 (l)=(k)+(b)+(g)-(h)

(for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)

Calendar Year 2011

Shading denotes an input

		Attachment F		
		Reference	Reading	Reference
Line No.	I. INVESTMENT BASE	Section:		
1	Transmission Plant	(A)(1)(a)	0	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	0	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		0	
5	Accumulated Depreciation	(A)(1)(d)	0	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	0	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	0	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	0	Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		0	
10	Prepayments	(A)(1)(h)	0	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	0	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	11,812	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		11,812	
II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	945	Worksheet 2
15	Depreciation Expense	(B)	0	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	0	Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)	0	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	0	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	0	Worksheet 4, line 17 column 5
20	Operation & Maintenance Expense	(G)	0	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	0	Worksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	94,494	Worksheet 7
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	0	
28	Transmission Rents Received from Electric Property	(O)	0	
29	Total Revenue Requirements (Line 14 thru 28)		95,439	

Reading Municipal Light Department

Annual Revenue Requirements

Calendar Year 2011

Shading denotes an input

	CAPITALIZATION 12/31/2009	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 550,000	100.00%	8.00%	8.00%	
PREFERRED STOCK	0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	0	0.00%	0.00%	0.00%	0.00%
TOTAL INVESTMENT RETURN	\$ 550,000	100.00%		8.00%	0.00%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0800

(b) Federal Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / \text{Federal Income Tax Rate}}{1} \right) \times \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}}$$

=
$$\left(\frac{0.0000 + \left(\frac{0 + 0}{11,812} \right)}{1} \right) \times \frac{0}{0}$$

= 0.0000000

(c) State Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / \text{Federal Income Tax Rate}}{1} \right) + \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}} \times \text{State Income Tax Rate}$$

=
$$\left(\frac{0.0000 + \left(\frac{0 + 0}{11,812} \right)}{1} \right) + \frac{0.0000000}{0} \times 0$$

= 0.0000000

(a)+(b)+(c) **Cost of Capital Rate** = 0.0800000

	(PTF)	
INVESTMENT BASE	\$ 11,812	From Worksheet 1
x Cost of Capital Rate	0.0800000	
= Investment Return and Income Taxes	<u>945</u>	To Worksheet 1

Reading Municipal Light Department

Calendar Year 2011

Shading denotes an input

Line No.		(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Mass DTE AR Reference for col (1)
<u>Transmission Plant</u>							
1	Transmission Plant	\$ -		0		0	Line 1, Worksheet 5 Page 8B line 29(g)
2	General Plant	\$ 22,510,246	0.0000% (a)	0	0.0000%	0	
3	Total (line 1+2)			0		0	
4	<u>Transmission Plant Held for Future Use</u>	0		0	0.0000%	0	None known
<u>Transmission Accumulated Depreciation</u>							
5	Transmission Accum. Depreciation	1,978,626		1,978,626	0.0000%	0	Page 8A, line 31(g) less Page 16, line 31(g) Page 8B, line 29(g) less Page 17, line 29(g)
6	General Plant Accum.Depreciation	16,518,728	0.0000% (a)	0	0.0000%	0	
7	Total (line 5+6)			1,978,626		0	
<u>Transmission Accumulated Deferred Taxes</u>							
8	Accumulated Deferred Taxes (281-283)	0	6.3663% (c)	0	0.0000%	0	None known
9	Accumulated Deferred Taxes (190)	0	6.3663% (c)	0	0.0000%	0	None known
10	Total (line 8+9)			0		0	
11	<u>Transmission loss on Reacquired Debt</u>	0	6.3663% (c)	0	0.0000%	0	None known
<u>Other Regulatory Assets</u>							
12	FAS 106	0	0.0000% (a)	0	0.0000%	0	None known
13	FAS 109	0	6.3663% (c)	0	0.0000%	0	None known
14	Other Regulatory Liabilities (254.DK)	0	6.3663% (c)	0	0.0000%	0	
15	Total (line 12+13+14)	0		0		0	
16	<u>Transmission Prepayments</u>	0	0.0000% (a)	0	0.0000%	0	Assumed none
17	<u>Transmission Materials and Supplies</u>	0	0.0000%	0	0.0000%	0	Assumed none
<u>Cash Working Capital</u>							
18	Operation & Maintenance Expense					0	Worksheet 1, Line 20
20	Administrative & General Expense					0	Worksheet 1, Line 21
21	Transmission Support Expense					94,494	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					94,494	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					11,812	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

Reading Municipal Light Department

Calendar Year 2011

(2)

(4)

Shading denotes an input

Line No.	(1) Total	Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Mass DTE AR Reference for col (1)
<u>Depreciation Expense</u>						
1	187,720		187,720	0.0000%	0	Page 16, line 31(d)
2	767,252	0.0000% (a)	0	0.0000%	0	Page 17, line 29(d)
3			187,720		0	
4	0	6.3663% (c)	0	0.0000%	0	None known
5	0	6.3663% (c)	0	0.0000%	0	None known
<u>Property Taxes *</u>						
6	2,188,919	6.3663%	139,353	0.0000%	0	DTE, p. 21 line 24
7	2,179,275	0.0000% (a)	0	0.0000%	0	DTE, p. 21 line 24
8			139,353		0	
<u>Transmission Operation and Maintenance</u>						
9	8,652,725		8,652,725	0	0	Page 40, line 50(b)
10	8,650,000		8,650,000	0	0	Page 40, line 38(b)
11	0		0	0	0	Page 40, line 34(b)
12	0		0	0	0	Page 40, line 35(b) 40(b)
13	2,725		2,725	0.0000%	0	
<u>Transmission Administrative and General</u>						
14	5,400,731					Page 42, line 6(b)
15	385,535					Page 41, line 47(b)
16	0					Page 41, line 50(b)
17	181,688					assumed none
18	4,833,508	0.0000% (a)	0	0.0000%	0	
19	385,535	6.3663% (c)	24,544	0.0000%	0	
20	0	6.3663% (c)	0	0.0000%	0	
21	0	6.3663% (c)	0	0.0000%	0	
22	5,219,043		24,544		0	
23	81,121	0.0000% (a)	0	0.0000%	0	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

Shading denotes an input

Calendar Year 2011

Line No.			Mass DTE AR Reference
<u>PTF Transmission Plant Allocation Factor</u>		Reading	
1	PTF Transmission Investment	0	See Worksheet Page 8A, line 31(g)
2	Total Transmission Investment	7,743,423	
3	Percent Allocation (Line 1/Line 2)	0.0000%	
<u>Transmission Wages and Salaries Allocation Factor</u>			
4	Direct Transmission Wages and Salaries	0	See Worksheet Worksheet 6 & 6a of 8
5	Affiliated Company Transmission Wages and Salaries	0	
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	0	
7	Total Wages and Salaries	7,367,656	Page 42, line 24 (c) Page 41, line 43(b) Worksheet 6 & 6a of 8
8	Administrative and General Wages and Salaries	728,926	
9	Affiliated Company Wages and Salaries less A&G	0	
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	6,638,730	
11	Percent Allocation (Line 6/Line 10)	0.0000%	
<u>Plant Allocation Factor</u>			
12	Total Transmission Investment	7,743,423	Line 2 Worksheet 3, Line 2
13	plus Transmission-Related General Plant (Line 2 of Wkst. 3)	0	
14	= Revised Numerator (Line 12 + Line 13)	7,743,423	
15	Total Plant in Service	121,630,767	Page 8B, line 30 (g)
16	Percent Allocation (Line 14 / Line 15)	6.3663%	

Affiliated Company Wages and Salaries

Calendar Year 2011

Shading denotes an input

Line		Reading
"Affiliated" Transmission Wages and Salaries #560 - 573		
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11 = 1 thru 10	Total Transmission	0
12 = Total "Affiliated" Wages and Salaries		0
Less "Affiliated" Administrative and General Salaries #920 - 935		
13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
21 = 13 thru 20		0
22 = 12 less 21	Total "Affiliated" less A&G	0

READING

PTF Revenue Requirements

Sheet: Worksheet 7

Worksheet 7 of 7

Calendar Year 2011

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	FERC Form 1	TOTAL	
			Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	332.(g); [332.1(g) for HWP]		2,130
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
	Schedule 125 Payments			0
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			12,963
	Comerford 115 kV Substation			
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	332.1(g); [332(g) for CL&P]		30,710
NEP	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 394 line	332(g)		2,689
	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			2,541
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310 line	330.1(n)		14,298
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
	Seabrook			29,163
Total =			0	94,494

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

Sheet: Input Panel

NEPOOL Tariff Billing
NEPOOL Annual Transmission Revenue Requirements
per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3

Shading denotes an input

Submitted on:	<u>14-May-11</u>
Revenue Requirements for (year):	<u>Calendar Year 2011</u>
Customer:	<u>Reading Municipal Light Department</u>
Customer's NABs Number:	<u>148</u>
Name of Participant responsible for customer's billing:	<u>Bill Seldon</u>
DUNS number of Participant responsible for customer's billing:	<u>86-703-4654</u>

		<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>
Total of Attachment F - Sections A through I	=	<u> </u> (a)	<u>277,971</u> (f)
Total of Attachment F - Section J - Support Revenue		<u>0</u> (b)	<u>0</u> (g)
Total of Attachment F - Section K - Support Expense		<u>0</u> (c)	<u> </u> (h)
Total of Attachment F - Section (L through O)		<u>0</u> (d)	<u>0</u> (i)
Sub Total - Sum (A through I) - J + K + (L through O)		<u>0</u> (e)=(a)-(b)+(c)+(d)	<u>277,971</u> (j)

Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements
and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:

277,971 (k) = (e) + (j)

Total of Attachment F - Section J - Pre-97 Support Revenue (from above)	<u>0</u> (b)
Total of Attachment F - Section J - Post-96 Support Revenue (from above-)	<u>0</u> (g)
Total of Attachment F - Section K - Post-96 Support Expense (from above)	<u>0</u> (h)

Voting Share Total for Participant's R Value: 277,971 (l)=(k)+(b)+(g)-(h)

(for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)

Calendar Year 2011

Shading denotes an input

		Attachment F		
		Reference	Reading	Reference
Line No.	I. INVESTMENT BASE	Section:		
1	Transmission Plant	(A)(1)(a)	2,638,470	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	0	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		2,638,470	
5	Accumulated Depreciation	(A)(1)(d)	674,225	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	0	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	0	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	0	Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		1,964,245	
10	Prepayments	(A)(1)(h)	0	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	0	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	1,162	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		1,965,407	
II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	157,233	Worksheet 2
15	Depreciation Expense	(B)	63,963	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	0	Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)	0	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	47,483	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	0	Worksheet 4, line 17 column 5
20	Operation & Maintenance Expense	(G)	929	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	8,363	Worksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	0	Worksheet 7
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	0	
28	Transmission Rents Received from Electric Property	(O)	0	
29	Total Revenue Requirements (Line 14 thru 28)		277,971	

Reading Municipal Light Department

Annual Revenue Requirements

Calendar Year 2011

Shading denotes an input

	CAPITALIZATION 12/31/2009	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 550,000	100.00%	8.00%	8.00%	
PREFERRED STOCK	0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	0	0.00%	0.00%	0.00%	0.00%
TOTAL INVESTMENT RETURN	\$ 550,000	100.00%		8.00%	0.00%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0800

(b) Federal Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / \text{Federal Income Tax Rate}}{1} \right) \times \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}}$$

=
$$\left(\frac{0.0000 + \left(\frac{0 + 0}{1,965,407} \right)}{1} \right) \times \frac{0}{0}$$

= 0.0000000

(c) State Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / \text{Federal Income Tax Rate}}{1} \right) + \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}} \times \text{State Income Tax Rate}$$

=
$$\left(\frac{0.0000 + \left(\frac{0 + 0}{1,965,407} \right)}{1} \right) + \frac{0.0000000}{0} \times 0$$

= 0.0000000

(a)+(b)+(c) **Cost of Capital Rate** = 0.0800000

	(PTF)	
INVESTMENT BASE	\$ 1,965,407	From Worksheet 1
x Cost of Capital Rate	0.0800000	
= Investment Return and Income Taxes	<u>157,233</u>	To Worksheet 1

Reading Municipal Light Department

Calendar Year 2011

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Mass DTE AR Reference for col (1)
<u>Transmission Plant</u>						
1	\$ 2,638,470		2,638,470		2,638,470	Line 1, Worksheet 5
2	\$ 22,510,246	0.0000% (a)	0	34.0737%	0	Page 8B line 29(g)
3			2,638,470		2,638,470	
4	0		0	34.0737%	0	None known
<u>Transmission Accumulated Depreciation</u>						
5	1,978,725		1,978,725	34.0737%	674,225	Page 8A, line 31(g) less Page 16, line 31(g)
6	16,518,728	0.0000% (a)	0	34.0737%	0	Page 8B, line 29(g) less Page 17, line 29(g)
7			1,978,725		674,225	
<u>Transmission Accumulated Deferred Taxes</u>						
8	0	6.3663% (c)	0	34.0737%	0	None known
9	0	6.3663% (c)	0	34.0737%	0	None known
10			0		0	
11	0	6.3663% (c)	0	34.0737%	0	None known
<u>Other Regulatory Assets</u>						
12	0	0.0000% (a)	0	34.0737%	0	None known
13	0	6.3663% (c)	0	34.0737%	0	None known
14	0	6.3663% (c)	0	34.0737%	0	
15	0		0		0	
16	0	0.0000% (a)	0	34.0737%	0	Assumed none
17	0	0.0000%	0	34.0737%	0	Assumed none
<u>Cash Working Capital</u>						
19					929	Worksheet 1, Line 20
20					8,363	Worksheet 1, Line 21
21					0	Worksheet 1, Line 24
22					9,292	
23					0.125	x 45 / 360
24					1,162	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

Reading Municipal Light Department

Calendar Year 2011

(2)

(4)

Shading denotes an input

Line No.	(1) Total	Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Mass DTE AR Reference for col (1)
<u>Depreciation Expense</u>						
1	187,720		187,720	34.0737%	63,963	Page 16, line 31(d)
2	767,253	0.0000% (a)	0	34.0737%	0	Page 17, line 29(d)
3			187,720		63,963	
4	0	6.3663% (c)	0	34.0737%	0	None known
5	0	6.3663% (c)	0	34.0737%	0	None known
<u>Property Taxes *</u>						
6	2,188,919	6.3663%	139,353	34.0737%	47,483	DTE, p. 21 line 24
7	2,188,919	0.0000% (a)	0	34.0737%	0	DTE, p. 21 line 24
8			139,353		47,483	
<u>Transmission Operation and Maintenance</u>						
9	8,652,725		8,652,725	0.340737	2,948,304	Page 40, line 50(b)
10	8,650,000		8,650,000	0.340737	2,947,375	Page 40, line 38(b)
11	0		0	0.340737	0	Page 40, line 34(b)
12	0		0	0.340737	0	Page 40, line 35(b) 40(b)
13	2,725		2,725	34.0737%	929	
<u>Transmission Administrative and General</u>						
14	5,400,731					Page 42, line 6(b)
15	385,535					Page 41, line 47(b)
16	0					Page 41, line 50(b)
17	181,688					assumed none
18	4,833,508	0.0000% (a)	0	34.0737%	0	
19	385,535	6.3663% (c)	24,544	34.0737%	8,363	
20	0	6.3663% (c)	0	34.0737%	0	
21	0	6.3663% (c)	0	34.0737%	0	
22	5,219,043		24,544		8,363	
23	81,121	0.0000% (a)	0	34.0737%	0	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

Shading denotes an input

<u>Line No.</u>	<u>Mass DTE AR Reference</u>

PTF Transmission Plant Allocation Factor

Reading

1	PTF Transmission Investment	2,638,470	See Worksheet
2	Total Transmission Investment	7,743,423	Page 8A, line 31(g)
3	Percent Allocation (Line 1/Line 2)	34.0737%	

Transmission Wages and Salaries Allocation Factor

4	Direct Transmission Wages and Salaries	0	See Worksheet
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 & 6a of 8
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	0	
7	Total Wages and Salaries	7,367,656	Page 42, line 24 (c)
8	Administrative and General Wages and Salaries	728,926	Page 41, line 43(b)
9	Affiliated Company Wages and Salaries less A&G	0	Worksheet 6 & 6a of 8
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	6,638,730	
11	Percent Allocation (Line 6/Line 10)	0.0000%	

Plant Allocation Factor

12	Total Transmission Investment	7,743,423	Line 2
13	<i>plus Transmission-Related General Plant (Line 2 of Wkst. 3)</i>	0	Worksheet 3, Line 2
14	<i>= Revised Numerator (Line 12 + Line 13)</i>	7,743,423	
15	Total Plant in Service	121,630,767	Page 8B, line 30 (g)
16	Percent Allocation (Line 14 / Line 15)	6.3663%	

Sheet: Worksheet 6

Affiliated Company Wages and Salaries

Calendar Year 2011

Shading denotes an input

Line		Reading
"Affiliated" Transmission Wages and Salaries #560 - 573		
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11 = 1 thru 10	Total Transmission	0
12 = Total "Affiliated" Wages and Salaries		0
Less "Affiliated" Administrative and General Salaries #920 - 935		
13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
21 = 13 thru 20		0
22 = 12 less 21	Total "Affiliated" less A&G	0

READING

PTF Revenue Requirements

Sheet: Worksheet 7

Worksheet 7 of 8

Calendar Year 2011

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	FERC Form 1	TOTAL	
			Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	332.(g); [332.1(g) for HWP]		0
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
				0
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			0
	Comerford 115 kV Substation			
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	332.1(g); [332(g) for CL&P]		0
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 394 line	332(g)		0
	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			0
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310 line	330.1(n)		0
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
	Seabrook			0
Total =			0	0

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

Taunton Municipal Light Plant

Sheet: Input Panel

Input Panel

Regional Network Service
Annual Transmission Revenue Requirements
per Attachment F of the ISO New England Inc. Open Access Transmission Tariff

Shading denotes an input

Submitted on: 05/14/2012

Revenue Requirements for (year): 2011

Customer: Taunton Municipal Light Plant

Customer's NABs Number: 153

Name of Participant responsible for customer's billing: Michael Horrigan

DUNS number of Participant responsible for customer's billing: 04-661-6033

	Pre-97 Revenue Requirements	Post-96 Revenue Requirements
Total of Attachment F - Sections A through I =	109,877 (a)	0 (f)
	0	
Total of Attachment F - Section J - Support Revenue	0 (b)	0 (g)
	0	
Total of Attachment F - Section K - Support Expense	202,492 (c)	0 (h)
	0	
Total of Attachment F - Section L through O	0 (d)	0 (i)
Sub Total - Sum (A through I) - J + K + (L through O)	312,369 (e)=(a)-(b)+(c)+(d)	0 (j)=(f)-(g)+(h)+(i)
Forecasted Incremental Transmission Revenue Requirements		0 (m)
Annual True-up	35,430	0 (n)
Interest Charge on Annual True-up	1,181	- (o)
Total = (e) + (j) + (k) + (l) + (m) + (n) + (o)	348,980 (p)	0 (q)
Annual Projected 2008 Revenue Requirement Total = Sum of Pre-97 Revenue Requirements, plus Post-96 Revenue Requirements, plus Annual True-up, and plus Interest on Annual True-up:		348,980 (r) = (p)+(q)

Taunton Municipal Light Plant
Annual Revenue Requirements of pre-1997 & post-1996 PTF
for costs in 2011 and billed 06/11-05/12

RNS Rate

		Attachment F			
		Reference	Pre 1997	Post 1996	Reference
Line No.	I. INVESTMENT BASE	Section:			
1	Transmission Plant	I (A)(1)(a)	1,500,243	0	Worksheet 3, line 1 column 5
2	General Plant	I (A)(1)(b)	1,178	0	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	I (A)(1)(c)	0	0	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		1,501,421	0	
5	Accumulated Depreciation	I (A)(1)(d)	1,370,460	0	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	I (A)(1)(e)	0	0	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	I (A)(1)(f)	0	0	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	I (A)(1)(g)	0	0	Worksheet 3, line 15 column 5
9	Net Investment (Line 4-5-6+7+8)		130,961	0	
10	Prepayments	I (A)(1)(h)	0	0	Worksheet 3, line 16 column 5
11	Materials & Supplies	I (A)(1)(i)	0	0	Worksheet 3, line 17 column 5
12	Cash Working Capital	I (A)(1)(j)	26,812	0	Worksheet 3, line 24 column 5
13	Total Investment Base (Line 9+11+12+13)		185,680	0	
II. REVENUE REQUIREMENTS					
14	Investment Return and Income Taxes	I (A)	12,622	0	Worksheet 2
15	Depreciation Expense	I (B)	27,125	0	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	I (C)	0	0	Worksheet 4, line 4 column 5
17	Investment Tax Credit	I (D)	0	0	Worksheet 4, line 5 column 5
18	Property Taxes	I (E)	22,592	0	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	I (F)	108	0	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	I (G)	2,252	0	Worksheet 4, line 13 column 5
21	Administrative & General Expense	I (H)	4,151	0	Worksheet 4, line 22 column 5
22	Transmission Related Integrated Facilities Charge	I (I)	0	0	
23	Transmission Support Revenue	I (J)	0	0	Worksheet 7
24	Transmission Support Expense	I (K)	208,089	0	Worksheet 7
25	Transmission Related Expense from Generators	I (L)	0	0	
26	Transmission Related Taxes and Fees Charge	I (M)	0	0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	I (N)	0	0	Txm related Acct 456
28	Transmission Rents Received from Electric Properties	I (O)	0	0	Txm related Acct 454-rent
29	Total Revenue Requirements (Line 14 thru 28)		276,939	0	
III. CURRENT CALENDAR YEAR ESTIMATED INCREMENTAL REVENUE REQUIREMENT					
30	Carrying Charge Factor Base Revenue Requirement Numerator			0	
31	Post-2003 Enhanced Return Addition to Revenue Requirement			-	
32	Total Post-96 PTF Revenue Requirement			0	
33	Post-96 PTF Transmission Plant in Service			0	
34	Post-96 Carrying Charge Factor (Post-96 CCF)			0.0%	
35	Forecasted Post-96 PTF Plant Additions			0	
36	Forecasted Post-96 Localized PTF Plant Additions			0	
37	Forecasted Post-96 Pool-Supported PTF Plant Additions			0	
38	Post-96 Estimated Incremental Revenue Requirement			0	

RNS Rate

Taunton Municipal Light Plant
FERC Interest Calculation associated with Under / (Over)
True Up and Interest Calculation for 2011

1 2011 Actual Annual RR			312,369	0	Input Panel Subtotals
2 2011 Est. Transmission Revenue Requirements (as billed)	6/11-05/12	Appendix C	276,939	0	ATRR - Prior Year
3 True-up (Over)/Under (Line 1 - Line 2)			35,430	0	

Pre'97
Post'96

(Overcollection)/Undercollection
\$35,430
\$0

Initial Billing Period	Pre 1997 Balance	Post 1996 Balance	FERC Monthly Interest Rate	Pre 1997 Interest	Post 1996 Interest
June 2011	\$35,430	\$0	0.27%	\$96	\$0
July 2011	35,526	0	0.27%	96	\$0
August 2011	35,526	0	0.28%	99	\$0
September 2011	35,526	0	0.27%	96	\$0
October 2011	35,817	0	0.28%	100	\$0
November 2011	35,817	0	0.27%	97	\$0
December 2011	35,817	0	0.28%	100	\$0
January 2012	36,114	0	0.28%	101	\$0
February 2012	36,114	0	0.26%	94	\$0
March 2012	36,114	0	0.28%	101	\$0
April 2012	36,410	0	0.27%	98	\$0
May 2012	36,410	0	0.28%	102	\$0
		Total Interest		\$1,181	\$0
		True-Up		\$35,430	\$0
		Total TU & Int		\$36,611	\$0

Voting Share

Sheet: Input Panel

NEPOOL Tariff Billing NEPOOL Annual Transmission Revenue Requirements per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3

Shading denotes an input

Submitted on: 14-May-12

Revenue Requirements for (year): Calendar Year 2011

Customer: Taunton Municipal Lighting Plant

Customer's NABs Number: 153

Name of Participant responsible for customer's billing: Michael Horrigan

DUNS number of Participant responsible for customer's billing: 04-661-6033

	Pre-97 Revenue Requirements	Post-97 Revenue Requirements
Total of Attachment F - Sections A through I =	109,877 (a)	0 (f)
	0	
Total of Attachment F - Section J - Support Revenue	0 (b)	0 (g)
	0	
Total of Attachment F - Section K - Support Expense	202,492 (c)	0 (h)
Total of Attachment F - Section (L through O)	0 (d)	0 (i)
Sub Total - Sum (A through I) - J + K + (L through O)	312,369 (e)=(a)-(b)+(c)+(d)	0 (j)
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:		312,369 (k) = (e) + (j)
Total of Attachment F - Section J - Pre-97 Support Revenue (from above)	n/a	0 (b)
Total of Attachment F - Section J - Post-96 Support Revenue (from above-)	(k)	0 (g)
Total of Attachment F - Section K - Post-96 Support Expense (from above)	(l)	0 (h)
	(p)	
Voting Share Total for Participant's R Value:		312,369 (l)=(k)+(b)+(g)-(h)
(for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)		

Calendar Year 2011

Shading denotes an input

		Attachment F		
		Reference	Taunton	Reference
Line No.	I. INVESTMENT BASE	Section:		
1	Transmission Plant	(A)(1)(a)	1,500,243	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	84,976	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		1,585,219	
5	Accumulated Depreciation	(A)(1)(d)	1,425,907	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	0	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	0	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	0	Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		159,312	
10	Prepayments	(A)(1)(h)	1,064	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	16,046	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	27,981	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		204,403	
II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	16,352	Worksheet 2
15	Depreciation Expense	(B)	31,792	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	0	Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)	0	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	31,929	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	8,449	Worksheet 4, line 17 column 5
20	Operation & Maintenance Expense	(G)	2,252	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	19,103	Worksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	202,492	Worksheet 7
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	0	
28	Transmission Rents Received from Electric Property	(O)	0	
29	Total Revenue Requirements (Line 14 thru 28)		312,369	
			109,877	

Taunton Municipal Lighting Plant
Annual Revenue Requirements
Calendar Year 2011

Shading denotes an input

	CAPITALIZATION 12/31/2007	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 0	100.00%	8.00%	8.00%	
PREFERRED STOCK	0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	0	0.00%	0.00%	0.00%	0.00%
TOTAL INVESTMENT RETURN	\$ 0	100.00%		8.00%	0.00%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0800

(b) Federal Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / \text{Federal Income Tax Rate}}{1} \right) \times \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}}$$

=
$$\left(\frac{0.0000 + \left(\frac{0 + 0}{204,403} \right)}{1} \right) \times \frac{0}{0}$$

= 0.0000000

(c) State Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) / \text{Federal Income Tax Rate}}{1} \right) + \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}}$$

=
$$\left(\frac{0.0000 + \left(\frac{0 + 0}{204,403} \right)}{1} \right) + \frac{0.0000000}{0}$$

= 0.0000000

(a)+(b)+(c) **Cost of Capital Rate** = 0.0800000

	(PTF)	
INVESTMENT BASE	\$ 204,403	From Worksheet 1
x Cost of Capital Rate	0.0800000	
= Investment Return and Income Taxes	16,352	To Worksheet 1

Taunton Municipal Lighting Plant

Calendar Year 2011

PTF Revenue Requirements
Worksheet 3a of 7

Shading denotes an input

Line No.		(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Mass DTE AR Reference for col (1)
<u>Transmission Plant</u>							
1	Transmission Plant	\$ 7,283,794		7,283,794		1,500,243	Line 1, Worksheet 5 Page 8B line 29(g)
2	General Plant	30,598,917	1.3483% (a)	412,565	20.5970%	84,976	
3	Total (line 1+2)			7,696,359		1,585,219	
4	<u>Transmission Plant Held for Future Use</u>	0		0	20.5970%	0	None known
<u>Transmission Accumulated Depreciation</u>							
5	Transmission Accum. Depreciation	6,764,477		6,764,477	20.5970%	1,393,279	Page 8A, line 31(g) less Page 16, line 31(g) Page 8B, line 29(g) less Page 17, line 29(g)
6	General Plant Accum.Depreciation	11,748,989	1.3483% (a)	158,412	20.5970%	32,628	
7	Total (line 5+6)			6,922,889		1,425,907	
<u>Transmission Accumulated Deferred Taxes</u>							
8	Accumulated Deferred Taxes (281-283)	0	3.9971% (c)	0	20.5970%	0	None known
9	Accumulated Deferred Taxes (190)	0	3.9971% (c)	0	20.5970%	0	None known
10	Total (line 8+9)			0		0	
11	<u>Transmission loss on Reacquired Debt</u>	0	3.9971% (c)	0	20.5970%	0	None known
<u>Other Regulatory Assets</u>							
12	FAS 106	0	1.3483% (a)	0	20.5970%	0	None known
13	FAS 109	0	3.9971% (c)	0	20.5970%	0	None known
14	Other Regulatory Liabilities (254.DK)	0	3.9971% (c)	0	20.5970%	0	
15	Total (line 12+13+14)			0		0	
16	<u>Transmission Prepayments</u>	383,021.00	1.3483% (a)	5,164	20.5970%	1,064	
17	<u>Transmission Materials and Supplies</u>	1,949,008.00	3.9971%	77,904	20.5970%	16,046	
<u>Cash Working Capital</u>							
18	Operation & Maintenance Expense					2,252	Worksheet 1, Line 20
20	Administrative & General Expense					19,103	Worksheet 1, Line 21
21	Transmission Support Expense					202,492	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					223,847	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					27,981	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

Taunton Municipal Lighting Plant

Calendar Year 2011

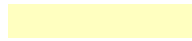
		(2)			(4)		
Shading denotes an input							
Line No.		(1) Total	Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Mass DTE AR Reference for col (1)
<u>Depreciation Expense</u>							
1	Transmission Depreciation	131,885		131,885	20.5970%	27,164	Page 16, line 31(d)
2	General Depreciation	1,666,329	1.3483% (a)	22,467	20.5970%	4,628	Page 17, line 29(d)
3	Total (line 1+2)			154,352		31,792	
<u>Amortization of Loss on Reacquired Debt</u>							
4		0	3.9971% (c)	0	20.5970%	0	None known
<u>Amortization of Investment Tax Credits</u>							
5		0	3.9971% (c)	0	20.5970%	0	None known
<u>Property Taxes *</u>							
6	Transmission Property Taxes	2,900,000	0.039971	115,916	20.5970%	23,875	
7	General Property Taxes	2,900,000	1.3483% (a)	39,101	20.5970%	8,054	
8	Total (line 6+7)			155,017		31,929	
<u>Transmission Operation and Maintenance</u>							
9	Operation and Maintenance	8,114,192		8,114,192	0.20597	1,671,280	Page 40, line 49(b)
10	Transmission of Electricity by Others - #565	7,863,483		7,863,483	0.20597	1,619,642	Page 40, line 38(b)
11	Load Dispatching - #561	11,603		11,603	0.20597	2,390	Page 40, line 34(b)
12	**Station Expenses & Rents - #562 / #567	228,167		228,167	0.20597	46,996	Page 40, line 35(b) 40(b)
13	O&M less lines 10, 11 & 12	10,939		10,939	20.5970%	2,252	
<u>Transmission Administrative and General</u>							
14	Administrative and General	5,979,346					Page 42, line 5(b)
15	less Property Insurance (#924)	499,307					Page 41, line 47(b)
16	less Regulatory Commission Expenses (#928)	0					Page 41, line 50(b)
17	less General Advertising Expense (#930.1)	81,633					930.1
18	Subtotal [line 14 minus (15 thru 17)]	5,398,406	1.3483% (a)	72,787	20.5970%	14,992	
19	PLUS Property Insurance alloc. using Plant Allocation	499,307	3.9971% (c)	19,958	20.5970%	4,111	
20	PLUS Regulatory Comm. Exp. (FERC Assessments)	0	3.9971% (c)	0	20.5970%	0	assumed none
21	PLUS Trans. Related General Advertising Expense	0	3.9971% (c)	0	20.5970%	0	
22	Total A&G [line 18 plus (19 thru 21)]	5,897,713		92,745		19,103	
<u>Payroll Tax Expense</u>							
23		3,042,312	1.3483% (a)	41,019	20.5970%	8,449	Footnote (d)
(a) Worksheet 5 of 8, line 11							
(b) Worksheet 5 of 8, line 3							
(c) Worksheet 5 of 8, line 16							
(d) Payroll taxes							
	Federal Unemployment						
	FICA	2,130,313	Combined				
	Medicare	167,513					
	CT Unemployment						
	MA Unemployment	744,486					
	MA Universal Health						
	VT Unemployment						
	NH Unemployment						
	Total	3,042,312	To Line 23				

Calendar Year 2011

Shading denotes an input

<u>Line No.</u>			<u>Mass DTE AR Reference</u>
	<u>PTF Transmission Plant Allocation Factor</u>	<u>Taunton</u>	
1	PTF Transmission Investment	1,500,243	See Worksheet
2	Total Transmission Investment	7,283,794	Page 8A, line 31(g)
3	Percent Allocation (Line 1/Line 2)	20.5970%	
	<u>Transmission Wages and Salaries Allocation Factor</u>		
4	Direct Transmission Wages and Salaries	180,325	See Worksheet
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 & 6a of 8
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	180,325	
7	Total Wages and Salaries	15,663,537	Page 42, line 24©
8	Administrative and General Wages and Salaries	2,289,058	Page 41, line 43(b)
9	Affiliated Company Wages and Salaries less A&G	0	Worksheet 6 & 6a of 8
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	13,374,479	
11	Percent Allocation (Line 6/Line 10)	1.3483%	
	<u>Plant Allocation Factor</u>		
12	Total Transmission Investment	7,283,794	Line 2
13	plus Transmission-Related General Plant (Line 2 of Wkst. 3)	412,565	Worksheet 3, Line 2
14	= Revised Numerator (Line 12 + Line 13)	7,696,359	
15	Total Plant in Service	192,549,282	Page 8B, line 29(g)
16	Percent Allocation (Line 14 / Line 15)	3.9971%	

Affiliated Company Wages and Salaries

 Shading denotes an input

Calendar Year 2011

Line		Taunton
"Affiliated" Transmission Wages and Salaries		
#560 - 573		
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11 = 1 thru 10	Total Transmission	0
12 = Total "Affiliated" Wages and Salaries		0
Less "Affiliated" Administrative and General Salaries		
#920 - 935		
13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
21 = 13 thru 20		0
22 = 12 less 21	Total "Affiliated" less A&G	0

TAUNTON

PTF Revenue Requirements

Sheet: Worksheet 7

Calendar Year 2011

Worksheet 7 of 7

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	FERC Form 1	TOTAL	
			Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	332.(g); [332.1(g) for HWP]		1,626
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			11,194
	Comerford 115 kV Substation			
	NEH HQ - II			69,704
	NHH-HQ-II			85,662
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	NEPAC-HQ-11	332.1(g); [332(g) for CL&P]		23,307
	345 kV Golden Hills-Mystic 349 line			
	HQ-1	332(g)		5,991
	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			401
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310 line	330.1(n)		
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
	Seabrook			4,607
Total =			0	202,492

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

The United Illuminating Company

Sheet: Input Panel

Input Panel

Regional Network Service
Annual Transmission Revenue Requirements
per Attachment F of the ISO New England Inc. Open Access Transmission Tariff

 Shading denotes an input

Submitted on: 5/31/2012

Revenue Requirements for (year): 2012

Customer: The United Illuminating Company

Customer's NABs Number: 51

Name of Participant responsible for customer's billing: The United Illuminating Company

DUNS number of Participant responsible for customer's billing: 00-691-7967

	<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>
Total of Attachment F - Sections A through I =	21,058,925 (a)	74,377,917 (f)
Total of Attachment F - Section J - Support Revenue	0 (b)	0 (g)
Total of Attachment F - Section K - Support Expense	706,862 (c)	0 (h)
Total of Attachment F - Section L through O	(45,513) (d)	0 (i)
Sub Total - Sum (A through I) - J + K + (L through O)	21,720,274 (e)=(a)-(b)+(c)+(d)	74,377,917 (j)=(f)-(g)+(h)+(i)
Forecasted Incremental Transmission Revenue Requirements	0 n/a	13,987,815 (m)
Annual True-up	(214,914) (k)	4,344,943 (n)
Interest Charge on Annual True-up	(7,162) (l)	144,788 (o)
Total = (e) + (j) + (k) + (l) + (m) + (n) + (o)	21,498,198 (p)	92,855,464 (q)
Annual Projected 2012 Revenue Requirement Total = Sum of Pre-97 Revenue Requirements, plus Post-96 Revenue Requirements, plus Annual True-up, and plus Interest on Annual True-up:		<u>114,353,662 (r) = (p)+(q)</u>

The United Illuminating Company
Annual Revenue Requirements of pre-1997 PTF
for costs in 2011

Sheet: Worksheet 1

Shading denotes an input

		Attachment F Reference	Pre-1997	Pre-1996
Line No.	I. INVESTMENT BASE	<i>Section:</i>		
1	Transmission Plant	I (A)(1)(a)	109,276,494	372,213,537
2	General Plant	I (A)(1)(b)	2,569,266	8,751,340
3	Plant Held For Future Use	I (A)(1)(c)	3,187,984	10,858,794
4	Total Plant (Lines 1+2+3)		115,033,744	391,823,671
5	Accumulated Depreciation	I (A)(1)(d)	18,815,481	64,088,592
6	Accumulated Deferred Income Taxes	I (A)(1)(e)	19,630,050	66,863,148
7	Loss On Reacquired Debt	I (A)(1)(f)	899,763	3,064,741
8	Other Regulatory Assets	I (A)(1)(g)	7,401,279	25,209,964
9	Net Investment (Line 4-5-6+7+8)		84,889,255	289,146,636
10	Prepayments	I (A)(1)(h)	69,996	238,416
11	Materials & Supplies	I (A)(1)(i)	37,696	128,398
12	Cash Working Capital	I (A)(1)(j)	751,554	2,258,955
13	Total Investment Base (Line 9+11+12+13)		85,748,501	291,772,405
II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	I (A)	11,094,964	37,752,490
15	Depreciation Expense	I (B)	2,491,628	8,486,891
16	Amortization of Loss on Reacquired Debt	I (C)	57,164	194,710
17	Investment Tax Credit	I (D)	(10,213)	(34,789)
18	Property Taxes	I (E)	1,989,591	6,776,873
19	Payroll Tax Expense	I (F)	130,220	443,552
20	Operation & Maintenance Expense	I (G)	3,059,512	10,421,197
21	Administrative & General Expense	I (H)	2,246,059	7,650,442
22	Transmission Related Integrated Facilities Charge	I (I)	0	0
23	Transmission Support Revenue	I (J)	0	0
24	Transmission Support Expense	I (K)	706,862	0
25	Transmission Related Expense from Generators	I (L)	0	0
26	Transmission Related Taxes and Fees Charge	I (M)	0	0
27	Revenue for ST Trans. Service Under NEPOOL Tariff	I (N)	(13,601)	0
28	Transmission Rents Received from Electric Property	I (O)	(31,912)	0
29	Total Revenue Requirements (Line 14 thru 28)		21,720,274	71,691,366

The United Illuminating Company
Annual Revenue Requirements of pre-1997 PTF
for costs in 2011

RNS Rate

Sheet: Worksheet 1

Worksheet 1 of 8

Shading denotes an input

		Attachment F Reference	UI	Reference
Line No.	I. INVESTMENT BASE	Section:		
1	Transmission Plant	I (A)(1)(a)	109,276,494	Worksheet 3, line 1 column 5
2	General Plant	I (A)(1)(b)	2,569,266	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	I (A)(1)(c)	3,187,984	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		115,033,744	
5	Accumulated Depreciation	I (A)(1)(d)	18,815,481	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	I (A)(1)(e)	19,630,050	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	I (A)(1)(f)	899,763	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	I (A)(1)(g)	7,401,279	Worksheet 3, line 15 column 5
9	Net Investment (Line 4-5-6+7+8)		84,889,255	
10	Prepayments	I (A)(1)(h)	69,996	Worksheet 3, line 16 column 5
11	Materials & Supplies	I (A)(1)(i)	37,696	Worksheet 3, line 17 column 5
12	Cash Working Capital	I (A)(1)(j)	751,554	Worksheet 3, line 24 column 5
13	Total Investment Base (Line 9+11+12+13)		85,748,501	
II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	I (A)	11,094,964	Worksheet 2
15	Depreciation Expense	I (B)	2,491,628	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	I (C)	57,164	Worksheet 4, line 4 column 5
17	Investment Tax Credit	I (D)	(10,213)	Worksheet 4, line 5 column 5
18	Property Taxes	I (E)	1,989,591	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	I (F)	130,220	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	I (G)	3,059,512	Worksheet 4, line 13 column 5
21	Administrative & General Expense	I (H)	2,246,059	Worksheet 4, line 22 column 5
22	Transmission Related Integrated Facilities Charge	I (I)	0	
23	Transmission Support Revenue	I (J)	0	Worksheet 7
24	Transmission Support Expense	I (K)	706,862	Worksheet 7
25	Transmission Related Expense from Generators	I (L)	0	
26	Transmission Related Taxes and Fees Charge	I (M)	0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	I (N)	(13,601)	Txm related Acct 456
28	Transmission Rents Received from Electric Property	I (O)	(31,912)	Txm related Acct 454-rent
29	Total Revenue Requirements (Line 14 thru 28)		21,720,274	

The United Illuminating Company
Annual Revenue Requirements of post-1996 PTF
for costs in 2011

RNS Rate

Sheet: Worksheet 1a

Worksheet 1a of 8

Shading denotes an input

		Attachment F Reference	UI	Reference
Line No.	I. INVESTMENT BASE	<i>Section:</i>		
1	Transmission Plant	I (A)(1)(a)	372,213,537	Worksheet 3a, line 1 column 5
2	General Plant	I (A)(1)(b)	8,751,340	Worksheet 3a, line 2 column 5
3	Plant Held For Future Use	I (A)(1)(c)	10,858,794	Worksheet 3a, line 4 column 5
4	Total Plant (Lines 1+2+3)		391,823,671	
5	Accumulated Depreciation	I (A)(1)(d)	64,088,592	Worksheet 3a, line 7 column 5
6	Accumulated Deferred Income Taxes	I (A)(1)(e)	66,863,148	Worksheet 3a, line 10 column 5
7	Loss On Reacquired Debt	I (A)(1)(f)	3,064,741	Worksheet 3a, line 11 column 5
8	Other Regulatory Assets	I (A)(1)(g)	25,209,964	Worksheet 3a, line 15 column 5
9	Net Investment (Line 4-5-6+7+8)		289,146,636	
10	Prepayments	I (A)(1)(h)	238,416	Worksheet 3a, line 16 column 5
11	Materials & Supplies	I (A)(1)(i)	128,398	Worksheet 3a, line 17 column 5
12	Cash Working Capital	I (A)(1)(j)	2,258,955	Worksheet 3a, line 24 column 5
13	Total Investment Base (Line 9+11+12+13)		291,772,405	
II. PRIOR CALENDAR YEAR ACTUAL REVENUE REQUIREMENT				
14	Investment Return and Income Taxes	I (A)	37,752,490	Worksheet 2a
15	Depreciation Expense	I (B)	8,486,891	Worksheet 4a, line 3 column 5
16	Amortization of Loss on Reacquired Debt	I (C)	194,710	Worksheet 4a, line 4 column 5
17	Investment Tax Credit	I (D)	(34,789)	Worksheet 4a, line 5 column 5
18	Property Taxes	I (E)	6,776,873	Worksheet 4a, line 8 column 5
19	Payroll Tax Expense	I (F)	443,552	Worksheet 4a, line 23 column 5
20	Operation & Maintenance Expense	I (G)	10,421,197	Worksheet 4a, line 13 column 5
21	Administrative & General Expense	I (H)	7,650,442	Worksheet 4a, line 22 column 5
22	Transmission Related Integrated Facilities Charge	I (I)	0	
23	Transmission Support Revenue	I (J)	0	Worksheet 7
24	Transmission Support Expense	I (K)	0	Worksheet 7
25	Transmission Related Expense from Generators	I (L)	0	
26	Transmission Related Taxes and Fees Charge	I (M)	0	
27	Revenue for ST Trans. Service Under NEPOOL Tar	I (N)	0	
28	Transmission Rents Received from Electric Property	I (O)	0	
29	Total Revenue Requirements (Line 14 thru 28)		71,691,366	0.192608164

III. CURRENT CALENDAR YEAR ESTIMATED INCREMENTAL REVENUE REQUIREMENT

30	Carrying Charge Factor Base Revenue Requirement Numerator	71,691,366	Sum of Lines 14 through 21
31	Post-2003 Enhanced Return Addition to Revenue Requirement	2,686,551	Worksheet 1b Line 6 Column 2 and L
32	Total Post-96 PTF Revenue Requirement	74,377,917	Line 30 + Line 31
33	Post-96 PTF Transmission Plant in Service	372,213,537	Line 1
34	Post-96 Carrying Charge Factor (Post-96 CCF)	0.199825932	Line 32 / Line 33
35	Forecasted Post-96 PTF Plant Additions	70,000,000	RSP March 2012 Update
36	Forecasted Post-96 Localized PTF Plant Additions		
37	Forecasted Post-96 Pool-Supported PTF Plant Additions	70,000,000	Line 35 - Line 36
38	Post-96 Estimated Incremental Revenue Requirement	13,987,815	Line 34 * Line 37

The United Illuminating Company
Annual Revenue Requirements of post-2003 PTF Incremental Return
for costs in 2011

RNS Rate

Worksheet 1b of 8

		(1) Total Transmission	(2) Post-2003 ¹ PTF	(3) Post-2003 ² PTF	Total Transmission Reference
Line No.	I. INVESTMENT BASE				
1	Transmission Plant	547,462,753	309,533,625	187,107,309	Internal Plant Accounting
2	Accumulated Depreciation	90,230,643	28,519,395	17,239,443	Internal Plant Accounting
3	Accumulated Deferred Income Taxes	98,344,309	34,947,688	21,125,226	Internal Plant Accounting
4	Other Regulatory Assets	37,079,565	0	0	Included on Line 3, above
5	Net Investment (Line 1-2-3+4)	395,967,365	246,066,542	148,742,640	
		0.723277269	0.794959004	0.794959004	
	II. ENHANCED RETURN ON POST-2003 TRANSMISSION PLANT				
6	Enhanced Return Addition to Revenue Requirement		2,063,022	623,529	Worksheet 2b
7	PTF Transmission Plant Allocation Factor		56.5397%		

Notes: 1. Incentive for New Trans Investment
Notes: 2. Incentive for used of Advanced Tech MN Proj

The United Illuminating Company
Annual Revenue Requirements of PTF Facilities
for costs in 2011

RNS Rate

Worksheet: 1 + 1a (Total pre-1997 and post-1996)

Worksheet 1c of 8

		Attachment F		
		Reference	UI	Reference
Line No.	I. INVESTMENT BASE	Section:		
1	Transmission Plant	I (A)(1)(a)	481,490,031	Worksheet 1 + Worksheet 1a
2	General Plant	I (A)(1)(b)	11,320,606	Worksheet 1 + Worksheet 1a
3	Plant Held For Future Use	I (A)(1)(c)	14,046,778	Worksheet 1 + Worksheet 1a
4	Total Plant (Lines 1+2+3)		506,857,415	Worksheet 1 + Worksheet 1a
5	Accumulated Depreciation	I (A)(1)(d)	82,904,073	Worksheet 1 + Worksheet 1a
6	Accumulated Deferred Income Taxes	I (A)(1)(e)	86,493,198	Worksheet 1 + Worksheet 1a
7	Loss On Recquired Debt	I (A)(1)(f)	3,964,504	Worksheet 1 + Worksheet 1a
8	Other Regulatory Assets	I (A)(1)(g)	32,611,243	Worksheet 1 + Worksheet 1a
9	Net Investment (Line 4-5-6+7+8)		374,035,891	Worksheet 1 + Worksheet 1a
10	Prepayments	I (A)(1)(h)	308,412	Worksheet 1 + Worksheet 1a
11	Materials & Supplies	I (A)(1)(i)	166,094	Worksheet 1 + Worksheet 1a
12	Cash Working Capital	I (A)(1)(j)	3,010,509	Worksheet 1 + Worksheet 1a
13	Total Investment Base (Line 9+11+12+13)		377,520,906	
II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	I (A)	48,847,454	Worksheet 1 + Worksheet 1a
15	Depreciation Expense	I (B)	10,978,519	Worksheet 1 + Worksheet 1a
16	Amortization of Loss on Recquired Debt	I (C)	251,874	Worksheet 1 + Worksheet 1a
17	Investment Tax Credit	I (D)	(45,002)	Worksheet 1 + Worksheet 1a
18	Property Taxes	I (E)	8,766,464	Worksheet 1 + Worksheet 1a
19	Payroll Tax Expense	I (F)	573,772	Worksheet 1 + Worksheet 1a
20	Operation & Maintenance Expense	I (G)	13,480,709	Worksheet 1 + Worksheet 1a
21	Administrative & General Expense	I (H)	9,896,501	Worksheet 1 + Worksheet 1a
22	Transmission Related Integrated Facilities Charge	I (I)	0	Worksheet 1 + Worksheet 1a
23	Transmission Support Revenue	I (J)	0	Worksheet 1 + Worksheet 1a
24	Transmission Support Expense	I (K)	706,862	Worksheet 1 + Worksheet 1a
25	Transmission Related Expense from Generators	I (L)	0	Worksheet 1 + Worksheet 1a
26	Transmission Related Taxes and Fees Charge	I (M)	0	Worksheet 1 + Worksheet 1a
27	Revenue for ST Trans. Service Under NEPOOL Tariff	I (N)	(13,601)	Worksheet 1 + Worksheet 1a
28	Transmission Rents Received from Electric Property	I (O)	(31,912)	Worksheet 1 + Worksheet 1a
29	Historic Revenue Requirements (Line 14 thru 28)		93,411,640	
III. ENHANCED RETURN ON POST-2003 TRANSMISSION PLANT				
30	Enhanced Return Addition to Revenue Requirement		2,686,551	Worksheet 2b
IV. CURRENT CALENDAR YEAR ESTIMATED INCREMENTAL REVENUE REQUIREMENT				
31	Post-96 Estimated Incremental Revenue Requirement		13,987,815	
V. ANNUAL TRUE-UP				
32	Annual True-up		4,267,655	
VI. TOTAL ESTIMATED REVENUE REQUIREMENT				
33	Total Estimated Revenue Requirement		114,353,662	

The United Illuminating Company
Annual Revenue Requirements of pre-1997 PTF
for costs in 2011

Shading denotes an input

	CAPITALIZATION 12/31/2011	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 657,479,307	49.63%	6.14%	3.05%	
PREFERRED STOCK		0.00%		0.00%	0.00%
COMMON EQUITY	667,182,901	50.37%	11.64%	5.86%	5.86%
TOTAL INVESTMENT RETURN	\$ 1,324,662,208	100.00%		8.91%	5.86%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 8.91%

(b) Federal Income Tax =
$$\frac{\left(\frac{\text{R.O.E.} + \left(\left(\frac{\text{PTF Inv. Tax Credit} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) \right)}{1} \right) \times \text{Federal Income Tax Rate}}{\left(\frac{0.0586 + \left(\left(\frac{(10,213) + 89,944}{85,748,501} \right) \right)}{1} \right) \times 0.35}$$

= 0.0320545

(c) State Income Tax =
$$\frac{\left(\frac{\text{R.O.E.} + \left(\left(\frac{\text{PTF Inv. Tax Credit} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) \right)}{1} \right) + \text{Federal Income Tax}}{\left(\frac{0.0586 + \left(\left(\frac{(10,213) + 89,944}{85,748,501} \right) \right)}{1} \right) + 0.0320545} \times \text{State Income Tax Rate}$$

= 0.0082351

(a)+(b)+(c) Cost of Capital Rate = 0.1293896

(pre-1997 PTF)

INVESTMENT BASE	\$ 85,748,501	From Worksheet 1
x Cost of Capital Rate	0.1293896	
= Investment Return and Income Taxes	\$ 11,094,964	To Worksheet 1

The United Illuminating Company
Annual Revenue Requirements of post-1996 PTF
for costs in 2011

	<u>CAPITALIZATION</u> <u>12/31/2011</u>	<u>CAPITALIZATION</u> <u>RATIOS</u>	<u>COST OF</u> <u>CAPITAL</u>	<u>COST OF</u> <u>CAPITAL</u>	<u>EQUITY</u> <u>PORTION</u>
LONG-TERM DEBT	\$ 657,479,307	49.63%	6.14%	3.05%	
PREFERRED STOCK		0.00%		0.00%	0.00%
COMMON EQUITY	<u>667,182,901</u>	<u>50.37%</u>	11.64%	<u>5.86%</u>	<u>5.86%</u>
TOTAL INVESTMENT RETURN	\$ <u>1,324,662,208</u>	<u>100.00%</u>		<u>8.91%</u>	<u>5.86%</u>

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0891

(b) Federal Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\left(\frac{\text{PTF Inv. Tax Credit} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) \right)}{1} \right) \times \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}}$$

=
$$\left(\frac{0.0586 + \left(\left(\frac{(34,789) + 306,363}{291,772,405} \right) \right)}{1} \right) \times \frac{0.35}{0.35}$$

= 0.0320550

(c) State Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\left(\frac{\text{PTF Inv. Tax Credit} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) \right)}{1} \right) + \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}} \times \text{State Income Tax Rate}$$

=
$$\left(\frac{0.0586 + \left(\left(\frac{(34,789) + 306,363}{291,772,405} \right) \right)}{1} \right) + \frac{0.0320550}{0.0825} \times 0.0825$$

= 0.0082352

(a)+(b)+(c) **Cost of Capital Rate** = 0.1293902

(post-1996 PTF)

INVESTMENT BASE	\$ 291,772,405	From Worksheet 1a
x Cost of Capital Rate	0.1293902	
= Investment Return and Income Taxes	<u>\$ 37,752,490</u>	To Worksheet 1a

The United Illuminating Company
Annual Revenue Requirements of post-2003 PTF Incremental Return
for costs in 2011
Incremental Portion of ROE at 1% Adder

	CAPITALIZATION 12/31/2011	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 657,479,307	49.63%	#N/A		
PREFERRED STOCK					
COMMON EQUITY	667,182,901	50.37%	1.00%	0.50%	0.50%
TOTAL INVESTMENT RETURN	\$ 1,324,662,208	100.00%		0.50%	0.50%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0050

(b) Federal Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\left(\frac{\text{PTF Inv. Tax Credit} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) \right)}{1} \right) \times \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}}$$

=
$$\left(\frac{0.0050 + \left(\left(\frac{0 + 0}{246,066,542} \right) \right)}{1} \right) \times \frac{0.35}{0.35}$$

= 0.0026923

(c) State Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\left(\frac{\text{PTF Inv. Tax Credit} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right) \right)}{1} \right) + \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}} \times \text{State Income Tax Rate}$$

=
$$\left(\frac{0.0050 + \left(\left(\frac{0 + 0}{246,066,542} \right) \right)}{1} \right) + \frac{0.0026923}{0.0825} \times 0.0825$$

= 0.0006917

(a)+(b)+(c) **Cost of Capital Rate** = 0.0083840

(post-2003 PTF)

INVESTMENT BASE	\$ 246,066,542	From Worksheet 1b
x Cost of Capital Rate	0.0083840	
= Investment Return and Income Taxes	<u>\$ 2,063,022</u>	To Worksheet 1b

The United Illuminating Company
Annual Revenue Requirements of post-2003 PTF Incremental Return
for costs in 2011
Incremental Portion of ROE at 1% Adder

	CAPITALIZATION 12/31/2011	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 657,479,307	49.63%	#N/A		
PREFERRED STOCK					
COMMON EQUITY	667,182,901	50.37%	0.50%	0.25%	0.25%
TOTAL INVESTMENT RETURN	\$ 1,324,662,208	100.00%		0.25%	0.25%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0025

(b) Federal Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. Tax Credit} + \text{Eq. AFUDC of Deprec. Exp}}{\text{PTF Inv. Base}} \right)}{1} \right) \times \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}}$$

=
$$\left(\frac{0.0025 + \left(\frac{0 + 0}{148,742,640} \right)}{1} \right) \times \frac{0.35}{0.35}$$

= 0.0013462

(c) State Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. Tax Credit} + \text{Eq. AFUDC of Deprec. Exp}}{\text{PTF Inv. Base}} \right)}{1} \right) + \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}} \times \text{State Income Tax Rate}$$

=
$$\left(\frac{0.0025 + \left(\frac{0 + 0}{148,742,640} \right)}{1} \right) + \frac{0.0013462}{0.0825} \times 0.0825$$

= 0.0003458

(a)+(b)+(c) **Cost of Capital Rate** = 0.0041920

(post-2003 PTF)

INVESTMENT BASE	\$ 148,742,640	From Worksheet 1b
x Cost of Capital Rate	0.0041920	
= Investment Return and Income Taxes	<u>\$ 623,529</u>	To Worksheet 1b

The United Illuminating Company - 2011
Pre-1997 PTF

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
<u>Transmission Plant</u>						
1	547,462,753		547,462,753		109,276,494 (c)	Internal Company Record
2	118,747,910	10.8395% (a)		19.9605%	2,569,266	Page 207.100g
3			560,334,484		111,845,760	
4	15,971,438		15,971,438	19.9605%	3,187,984	Page 214.47d
<u>Transmission Accumulated Depreciation</u>						
5	90,230,643		90,230,643	19.9605%	18,010,519	Page 219.25b
5A			0	19.9605%	0	Included in Page 269.12f
6	37,204,218	10.8395% (a)	4,032,767	19.9605%	804,962	Page 219.28b
7			94,263,410		18,815,481	
<u>Transmission Accumulated Deferred Taxes</u>						
8	(406,361,657)	34.9280%	(141,934,017)	19.9605%	(28,330,789)	Internal Company Record
9	124,798,735	34.9280%	43,589,708	19.9605%	8,700,739	Internal Company Record
10			(98,344,309)		(19,630,050)	
11	12,905,724	34.9280%	4,507,712	19.9605%	899,763	Page 123.1 footnote
<u>Other Regulatory Assets/Liabilities</u>						
12	0	10.8395% (a)	0	19.9605%	0	Page 232
13	110,914,210	34.9280%	38,740,120	19.9605%	7,732,735	Internal Company Record
14	(4,754,224)	34.9280% (d)	(1,660,556)	19.9605%	(331,456)	Internal Company Record
15	106,159,986		37,079,565		7,401,279	
16	3,235,096	10.8395% (a)	350,670	19.9605%	69,996	Page 111.57c
17	188,852		188,852	19.9605%	37,696	Page 227.8c
<u>Cash Working Capital</u>						
19					3,059,512	Worksheet 1, Line 20
20					2,246,059	Worksheet 1, Line 21
21					706,862	Worksheet 1, Line 24
22					6,012,433	
23					0.125	x 45 / 360
24					751,554	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Pre-97 PTF

(d) Worksheet 5 of 8, line 16

The United Illuminating Company - 2011
post-1996 PTF

RNS Rate
Worksheet 3a of 8

Sheet: Worksheet 3a

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
<u>Transmission Plant</u>						
1	547,462,753		547,462,753		372,213,537 (c)	Internal Company Records
2	118,747,910	10.8395% (a)		67.9888%	8,751,340	Page 207.100g
3			<u>560,334,484</u>		<u>380,964,877</u>	
4	15,971,438		15,971,438	67.9888%	<u>10,858,794</u>	Page 214.47d
<u>Transmission Accumulated Depreciation</u>						
5	90,230,643		90,230,643	67.9888%	61,346,761	Page 219.25b
5A	0		0	67.9888%	0	Included in Page 269.12f
6	37,204,218	10.8395% (a)	4,032,767	67.9888%	2,741,831	Page 219.28b
7			<u>94,263,410</u>		<u>64,088,592</u>	
<u>Transmission Accumulated Deferred Taxes</u>						
8	(406,361,657)	34.9280%	(141,934,017)	67.9888%	(96,499,282)	Internal Company Records
9	124,798,735	34.9280%	43,589,708	67.9888%	29,636,134	Internal Company Records
10			<u>(98,344,309)</u>		<u>(66,863,148)</u>	
11	12,905,724	34.9280%	4,507,712	67.9888%	<u>3,064,741</u>	Page 123.1 footnote
<u>Other Regulatory Assets</u>						
12	0	10.8395% (a)	0	67.9888%	0	Page 232
13	110,914,210	34.9280%	38,740,120	67.9888%	26,338,956	Internal Company Records
14	(4,754,224)	34.9280% (d)	(1,660,556)	67.9888%	(1,128,992)	Page 278.3f
15	<u>106,159,986</u>		<u>37,079,565</u>		<u>25,209,964</u>	
16	3,235,096	10.8395% (a)	350,670	67.9888%	<u>238,416</u>	Page 111.57c
17	188,852		188,852	67.9888%	<u>128,398</u>	Page 227.8c
<u>Cash Working Capital</u>						
18					10,421,197	Worksheet 1a, Line 20
19					7,650,442	Worksheet 1a, Line 21
20					0	Worksheet 1a, Line 24
21					18,071,639	
22					0.125	x 45 / 360
23					<u>2,258,955</u>	
24						

(a) Worksheet 5a of 8, line 11

(b) Worksheet 5a of 8, line 3

(c) Post-96 PTF

(d) Worksheet 5 of 8, line 16

The United Illuminating Company - 2011
pre-1997 PTF

RNS Rate
Worksheet 4 of 8

Sheet: Worksheet 4

Shading denotes an input
BOLD denotes checked to FF1

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
Depreciation Expense						
1	11,768,011		11,768,011	19.9605%	2,348,958	Page 336.7f
2	6,594,016	10.8395% (a)		19.9605%	142,670	Page 336.10f
3			12,482,772		2,491,628	
4	819,930	34.9280% (c)	286,385	19.9605%	57,164	Page 117.64c
5	146,496	34.9280% (c)	51,168	19.9605%	10,213	Page 266.8f
Property Taxes						
6	9,967,626		9,967,626	19.9605%	1,989,591	Page 262.28a
7					0	Page 263.13i
8			9,967,626		1,989,591	
Transmission Operation and Maintenance						
9	94,799,524					Page 321.112b
10	77,996,997					Page 321.96b
11	1,474,720					Page 321.84b
12						Page 321.93b + 321.98b
13	15,327,807		15,327,807	19.9605%	3,059,512	
Transmission Administrative and General						
14	93,668,806					Page 323.197b
15	225,416					Page 323.185b
16	2,501,457					Page 323.189b
17	1,000					Page 323.191b
18	90,940,933	10.8395% (a)	9,857,582	19.9605%	1,967,626	
19	225,416	34.9280% (c)	78,733	19.9605%	15,716	Page 323.185b
20	591,513	100.0000%	591,513	19.9605%	118,069	Page 351.3d plus footnote
20A	2,074,752	34.9280% (c)	724,669	19.9605%	144,648	Page 351.1d + 351.5d
21	0		0	19.9605%	0	
22			11,252,498		2,246,059	
23	6,018,603 (e)	10.8395% (a)	652,389	19.9605%	130,220	
(a) Worksheet 5 of 8, line 11						
(b) Worksheet 5 of 8, line 3						
(c) Worksheet 5 of 8, line 16						
(d) Property taxes were allocated to transmission related general plant based on the ratio of general plant (Worksheet 3 of 8, line 2) to total plant in service (Worksheet 5 of 8, line 15) multiplied by the transmission wages and salaries allocation factor (Worksheet 5 of 8, line 11)						
(e) Payroll taxes FERC Form 1, page 263.i, 263.1i						
24	65,474					Page 263.5i
25	5,703,269					Page 263.4i
26 ***	0					
27	249,861					Page 263.12i
	6,018,603					To Line 23

** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments.

*** Medicare costs are included in FICA, Line 4

The United Illuminating Company - 2011
post-1996 PTF

RNS Rate
Worksheet 4a of 8

Sheet: Worksheet 4a

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
<u>Depreciation Expense</u>						
1	11,768,011		11,768,011	67.9888%	8,000,933	Page 336.7f
2	6,594,016	10.8395% (a)		67.9888%	485,958	Page 336.10f
3			12,482,772		8,486,891	
4	819,930	34.9280% (c)	286,385	67.9888%	194,710	Page 117.64c
5	146,496	34.9280% (c)	51,168	67.9888%	34,789	Page 266.8f
<u>Property Taxes</u>						
6	9,967,626		9,967,626	67.9888%	6,776,873	Page 262.28a
7	0	0.0000% 0	0	67.9888%	0	Page 263.13i
8			9,967,626		6,776,873	
<u>Transmission Operation and Maintenance</u>						
9	94,799,524					Page 321.112b
10	77,996,997					Page 321.96b
11	1,474,720					Page 321.84b
12	0					Page 321.93b + 321.98b
13	15,327,807		15,327,807	67.9888%	10,421,197	
<u>Transmission Administrative and General</u>						
14	93,668,806					Page 323.197b
15	225,416					Page 323.185b
16	2,501,457					Page 323.189b
17	1,000					Page 323.191b
18	90,940,933	10.8395% (a)	9,857,582	67.9888%	6,702,055	
19	225,416	34.9280% (c)	78,733	67.9888%	53,530	Page 323.185b
20	591,513	100.0000%	591,513	67.9888%	402,163	Page 351.3d plus footnote
20A	2,074,752	34.9280% (c)	724,669	67.9888%	492,694	Page 351.1d + 351.5d
21	0		0	67.9888%	0	
22			11,252,498		7,650,442	
23	6,018,603 (e)	10.8395% (a)	652,389	67.9888%	443,552	
(a) Worksheet 5a of 8, line 11						
(b) Worksheet 5a of 8, line 3						
(c) Worksheet 5a of 8, line 16						
(d) Property taxes were allocated to transmission related general plant based on the ratio of general plant (Worksheet 3 of 8, line 2) to total plant in service (Worksheet 5 of 8, line 15) multiplied by the transmission wages and salaries allocation factor (Worksheet 5 of 8, line 11)						
(e) Payroll taxes FERC Form 1, page 263.i ,263.1i						
24	65,474	Page 263.5i				
25	5,703,269	Page 263.4i				
26 ***	0					
27	249,861	Page 263.12i				
	6,018,603	To Line 23				

** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments.

*** Medicare costs are included in FICA, Line 25

The United Illuminating Company - 2011
pre-1997 PTF

Sheet: Worksheet 5

RNS Rate
Worksheet 5 of 8

Shading denotes an input

Line
No.

FERC Form 1
Reference

PTF Transmission Plant Allocation Factor

1	PTF Transmission Investment	109,276,494
2	Total Transmission Investment	547,462,753
3	Percent Allocation (line 1/2)	19.9605%

Internal Plant Accounting
Internal Company Records

Transmission Wages and Salaries Allocation Factor

4	Direct Transmission Wages and Salaries	5,148,053
5	Affiliated Company Transmission Wages and Salaries	0
6	Total Transmission Wages and Salaries (line 4+ 5)	5,148,053
7	Total Wages and Salaries	58,878,316
8	Administrative and General Wages and Salaries	11,385,052
9	Affiliated Company Wages and Salaries less A&G	0
10	Total Wages and Salaries net of A&G (line 7 - 8 + 9)	47,493,264
11	Percent Allocation (line 6/10)	10.8395%

Page 354.21b
Worksheet 6 of 8

Page 354.28b
Page 354.27b
Worksheet 6 of 8

Plant Allocation Factor

12	Total Transmission Investment	547,462,753
13	plus Transmission-related General Plant	12,871,731
14	Total Transmission Related Plant (line 12 + line 13)	560,334,484
15	Total Plant in Service	1,604,255,656
16	Percent Allocation (line 14/15)	34.9280%

Internal Company Records
Worksheet 3 of 8, Line 2

Page 207.104g

The United Illuminating Company - 2011
post-1996 PTF

Shading denotes an input

Line
No.

FERC Form 1
Reference

PTF Transmission Plant Allocation Factor

1	PTF Transmission Investment	372,213,537	Internal Plant Accounting
2	Total Transmission Investment	547,462,753	Internal Company Records
3	Percent Allocation (line 1/2)	<u>67.9888%</u>	

Transmission Wages and Salaries Allocation Factor

4	Direct Transmission Wages and Salaries	5,148,053	Page 354.21b
5	Affiliated Company Transmission Wages and Salaries	<u>0</u>	Worksheet 6 of 8
6	Total Transmission Wages and Salaries (line 4+ 5)	5,148,053	
7	Total Wages and Salaries	58,878,316	Page 354.28b
8	Administrative and General Wages and Salaries	11,385,052	Page 354.27b
9	Affiliated Company Wages and Salaries less A&G	<u>0</u>	Worksheet 6 of 8
10	Total Wages and Salaries net of A&G (line 7 - 8 + 9)	47,493,264	
11	Percent Allocation (line 6/10)	<u>10.8395%</u>	

Plant Allocation Factor

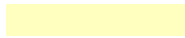
12	Total Transmission Investment	547,462,753	Internal Company Records
13	plus Transmission-related General Plant	<u>12,871,731</u>	Worksheet 3 of 8, Line 2
14	Total Transmission Related Plant (line 12 + line 13)	560,334,484	
15	Total Plant in Service	1,604,255,656	Page 207.104g
16	Percent Allocation (line 14/15)	<u>34.9280%</u>	

The United Illuminating Company - 2011

Sheet: Worksheet 6

RNS Rate
Worksheet 6 of 8

Affiliated Company Wages and Salaries-2011

 Shading denotes an input

<u>Line</u>		<u>UI</u>	
"Affiliated" Transmission Wages and Salaries #560 - 573			
1	560	0	
2	562	0	
3	564	0	
4	566	0	
5	568	0	
6	569	0	
7	570	0	
8	571	0	
9	572	0	
10	573	0	
11 = 1 thru 10	Total Transmission	0	To Worksheet 5
12 = Total "Affiliated" Wages and Salaries		0	
Less "Affiliated" Administrative and General Salaries #920 - 935			
13	920	0	
14	921	0	
15	923	0	
16	925	0	
17	926	0	
18	928	0	
19	930	0	
20	935	0	
21 = 13 thru 20		0	
22 = 12 less 21	Total "Affiliated" less A&G	0	To Worksheet 5

The United Illuminating Company - 2011
For the Year 2012

Sheet: Worksheet 7

RNS Rate
Worksheet 7 of 8

Input Revenues associated with the PTF Supporting Facilities in column (a) and expenses associated with the facilities in column (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

The United Illuminating Company - 2011			
Participant	PTF Supporting Facilities	Revenues (a)	Expenses (b)
Boston Edison:	345 kV Sherman - Medway 336 line 115 kV Somerville 402 Substation 115/345 kV North Cambridge 509 Substation 345 kV Golden Hills -Mystic 389 (x&y) line West Medway 345 kV breaker 115 kV Millbury-Medway 201 line HQ Phase II - AC in MA 345 kV "stabilizer" 342 line 345 kV Walpole - Medway 325 line 345 kV Carver - Walpole 331 line 345 kV Jordan Rd - Canal 342 line		24,759
Commonwealth:	Second Canal line 345 kV Pilgrim-Bridgewater (M.S.- Tower 77) 355 line 345 kV Myles Standish - Canal 342 line		
Central Maine Power:	345 kV Buxton-South Gorham 386 line 115 kV Wyman 164-167 lines 115 kV Maine Yankee transmission		
Eastern Utilities:	345 kV Carver - Walpole 331 line 345 kV Medway - Bridgewater 344 Line Northern Rhode Island transmission		
New England Power:	Chester SVC Comerford 115 kV Substation 345 kV Sandy-Tewksbury 337 line 345 kV Tewksbury-Woburn 338 line 115 kV Tewksbury - Woburn M139 line 115 kV Tewksbury - Woburn N140 line Moore 115 kV Substation HQ Phase II - AC in MA 345 kV Golden Hills-Mystic 349 line 345 kV NH/MA border-Tewksbury 394 line 115 kV Read - Washington V148 line		150,303
Northeast Utilities:	345 kV 363, 369 and 394 Seabrook lines Fairmont 115 kV Substation 345 kV Millstone-Manchester 310 line 345 kV E.Shore-Black Pond Jct. 387 line Substation Supply Agreements		176,848
Total =		0	706,862

Page 332.13g

Page 332.12g

Page 332.11g

Page 332.2g

**Summary of The United Illuminating Company System
Monthly Coincident Peaks for 2011
(Kilowatts)**

Shading denotes an input

	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
Day	24	1	3	1	31	8	22	8	14	10	17	19
Hour	1900	1800	1900	1100	1700	1700	1400	1600	1500	1600	1800	1800
The UI Co.	680,505	662,724	631,624	545,724	706,091	867,786	1,027,654	888,545	763,006	599,719	584,537	630,796
Hosley Substation	2,258	3,214	2,433	2,618	3,260	2,194	2,771	1,827	2,609	967	3,151	3,134
PSEG/Connecticut, (kW)	0	6,336	6,912	5,184	4,896	0	17,856	0	5,904	2,304	14,256	6,336
CP Energy / Brigdeport Energy	3,900	0	0	0	0	0	0	0	0	450	0	0
Annual UI System Average 12 CP Load												<u>724,457</u>

Day/Hour per 2011 12 CP detail file

24/1900 1/1800 3/1900 1/1100 31/1700 08/1700 22/1400 08/1600 14/1500 10/1600 17/1800 19/1800

The United Illuminating Company - 2011				RNS Rate	
YEAR	Equity AFUDC	DEBT AFUDC	Total AFUDC	AFUDC RATE	Equity AFUDC Rate
1941	0.00	1.00	1.00	0.00%	0.00%
1942	0.00	1.00	1.00	0.00%	0.00%
1943	0.00	1.00	1.00	0.00%	0.00%
1944	0.00	1.00	1.00	0.00%	0.00%
1945	0.00	1.00	1.00	0.00%	0.00%
1946	0.00	1.00	1.00	0.00%	0.00%
1947	0.00	1.00	1.00	0.00%	0.00%
1948	0.00	1.00	1.00	0.00%	0.00%
1949	0.00	1.00	1.00	0.00%	0.00%
1950	0.00	1.00	1.00	0.00%	0.00%
1951	0.00	1.00	1.00	0.00%	0.00%
1952	0.00	1.00	1.00	0.00%	0.00%
1953	0.00	1.00	1.00	0.00%	0.00%
1954	0.00	1.00	1.00	0.00%	0.00%
1955	0.00	1.00	1.00	0.00%	0.00%
1956	0.00	1.00	1.00	0.00%	0.00%
1957	0.00	1.00	1.00	0.00%	0.00%
1958	0.00	1.00	1.00	0.00%	0.00%
1959	0.00	1.00	1.00	0.00%	0.00%
1960	0.00	1.00	1.00	0.00%	0.00%
1961	0.00	1.00	1.00	0.00%	0.00%
1962	0.00	1.00	1.00	0.00%	0.00%
1963	0.00	1.00	1.00	0.00%	0.00%
1964	0.00	1.00	1.00	0.00%	0.00%
1965	0.00	1.00	1.00	0.00%	0.00%
1966	0.00	1.00	1.00	0.00%	0.00%
1967	0.00	1.00	1.00	0.00%	0.00%
1968	0.00	1.00	1.00	0.00%	0.00%
1969	0.00	1.00	1.00	0.00%	0.00%
1970	0.00	1.00	1.00	0.00%	0.00%
1971	0.00	1.00	1.00	0.00%	0.00%
1972	0.00	1.00	1.00	0.00%	0.00%
1973	0.00	1.00	1.00	0.00%	0.00%
1974	0.00	1.00	1.00	0.00%	0.00%
1975	0.00	1.00	1.00	0.00%	0.00%
1976	0.00	1.00	1.00	0.00%	0.00%
1977	2,518,016.00	2,419,271.00	4,937,287.00	8.30%	4.23%
1978	3,396,839.00	4,871,127.00	8,267,966.00	8.30%	3.41%
1979	4,574,700.00	10,925,831.00	15,500,531.00	9.90%	2.92%
1980	13,007.00	14,548.00	27,555.00	11.00%	5.19%
1981	21,022.00	7,091.00	28,113.00	9.00%	6.73%
1982	31,631.00	8,718.00	40,349.00	10.00%	7.84%
1983	40,443.00	11,964.00	52,407.00	10.25%	7.91%
1984	44,495.00	12,747.00	57,242.00	10.50%	8.16%
1985	46,083.00	16,540.00	62,623.00	10.75%	7.91%
1986	57,393.00	20,651.00	78,044.00	11.00%	8.09%
1987	54,933.00	26,486.00	81,419.00	13.00%	6.80%
1988	48,605.00	27,051.00	75,656.00	10.00%	6.58%
1989	38,968.00	26,475.00	65,443.00	12.30%	5.57%
1990	1,085.00	2,358.00	3,443.00	11.75%	3.39%
1991	1,259.00	3,931.00	5,190.00	10.88%	2.06%
1992	1,003.00	2,229.00	3,232.00	10.25%	3.18%
1993	999.00	3,068.00	4,067.00	8.75%	2.15%
1994	753.00	2,710.00	3,463.00	8.19%	1.78%
1995	390.00	2,372.00	2,762.00	8.00%	1.13%
1996	940.00	1,435.00	2,375.00	9.00%	3.56%
1997	336.00	1,239.00	1,575.00	7.50%	1.60%
1998	13.00	455.00	468.00	7.00%	0.19%
1999	575.00	1,660.00	2,235.00	7.75%	1.99%
2000	1,149.00	1,459.00	2,608.00	8.42%	3.71%
2001	1,123.00	789.00	1,912.00	9.02%	5.41%
2002	1,237.00	983.00	2,220.00	9.09%	5.41%
2003				8.08%	5.02%
2004					5.02%
2005					5.21%
2006					3.69%
2007					3.80%
2008					5.02%
2009					1.92%
2010					6.04%
2011					4.36%
Total					156.99%
Total divided by 41 years					3.83%
Transmission Depreciation					\$11,768,011
Equity AFUDC Portion of Depr. Exp.					\$450,609
PTF % Pre-97					19.9605%
Pre- 97 PTF Equity AFUDC Portion of Depr. Exp.					\$89,944
PTF % Post-96					67.9888%
Post-96 PTF Equity AFUDC Portion of Depr. Exp.					\$306,363

The United Illuminating Company 2011 Forecasted Plant in Service and PTF Transmission Revenue Requirements
(in thousands)

				(A)	(B)	(C)=(A)x(B)
				Estimated PTF Plant In- Service (in thousands)	Annual Carrying Charge	Forecasted PTF Revenue Requirement (in thousands)
Company	Project Name	RSP ID	Est ISD			
UI	Grand Avenue 115 kV Switching Station Rebuild.	976	05/2012	\$ 63,000,000	19.98%	\$ 12,589,034
UI	North Haven 115kV Capacitor Bank TRV Mitigation Project	1193	12/2012	\$ 5,000,000	19.98%	\$ 999,130
UI	Other			\$ 2,000,000	19.98%	\$ 399,652
UI	Total					
Total UI				<u><u>\$ 70,000,000</u></u>		<u><u>\$ 13,987,815</u></u>

The United Illuminating Company
Annual Revenue Requirements of pre-1997 & post-1996 PTF
for costs in 2011 06/11-05/12

RNS Rate

		Attachment F			
		Reference	Pre-97	Post 1996	Reference
Line No.	I. INVESTMENT BASE	Section:			
1	Transmission Plant	I (A)(1)(a)	110,399,304	357,244,350	Worksheet 3, line 1 column 5
2	General Plant	I (A)(1)(b)	2,396,992	7,756,497	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	I (A)(1)(c)	6,440,734	20,841,762	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		119,237,030	385,842,609	
			0	0	
5	Accumulated Depreciation	I (A)(1)(d)	18,825,578	60,918,239	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	I (A)(1)(e)	18,117,705	58,627,614	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	I (A)(1)(f)	973,713	3,150,866	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	I (A)(1)(g)	7,264,426	23,507,170	Worksheet 3, line 15 column 5
9	Net Investment (Line 4-5-6+7+8)		90,531,886	292,954,792	
			0	0	
10	Prepayments	I (A)(1)(h)	87,112	281,887	Worksheet 3, line 16 column 5
11	Materials & Supplies	I (A)(1)(i)	45,915	148,576	Worksheet 3, line 17 column 5
12	Cash Working Capital	I (A)(1)(j)	701,410	1,954,155	Worksheet 3, line 24 column 5
			0	0	
13	Total Investment Base (Line 9+11+12+13)		91,366,323	295,339,410	
II. REVENUE REQUIREMENTS					
14	Investment Return and Income Taxes	I (A)	11,504,418	37,187,957	Worksheet 2
15	Depreciation Expense	I (B)	2,671,837	8,645,876	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	I (C)	63,615	205,854	Worksheet 4, line 4 column 5
17	Investment Tax Credit	I (D)	(11,300)	(36,566)	Worksheet 4, line 5 column 5
18	Property Taxes	I (E)	2,068,063	6,692,106	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	I (F)	125,964	407,610	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	I (G)	2,103,450	6,806,614	Worksheet 4, line 13 column 5
21	Administrative & General Expense	I (H)	2,727,694	8,826,623	Worksheet 4, line 22 column 5
22	Transmission Related Integrated Facilities Charge	I (I)	0	0	
23	Transmission Support Revenue	I (J)	0	0	Worksheet 7
24	Transmission Support Expense	I (K)	780,134	0	Worksheet 7
25	Transmission Related Expense from Generators	I (L)	0	0	
26	Transmission Related Taxes and Fees Charge	I (M)	0	0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	I (N)	(41,372)	0	Txm related Acct 456
28	Transmission Rents Received from Electric Properties	I (O)	(57,315)	0	Txm related Acct 454-rent
			0	0	
29	Total Revenue Requirements (Line 14 thru 28)		21,935,188	68,736,074	
III. CURRENT CALENDAR YEAR ESTIMATED INCREMENTAL REVENUE REQUIREMENT					
30	Carrying Charge Factor Base Revenue Requirement Numerator			68,736,074	
31	Post-2003 Enhanced Return Addition to Revenue Requirement			3,039,380	
32	Total Post-96 PTF Revenue Requirement			71,775,454	
33	Post-96 PTF Transmission Plant in Service			357,244,350	
34	Post-96 Carrying Charge Factor (Post-96 CCF)			0.200914	
35	Forecasted Post-96 PTF Plant Additions			16,300,000	
36	Forecasted Post-96 Localized PTF Plant Additions			(24,972,760)	
37	Forecasted Post-96 Pool-Supported PTF Plant Additions			(8,672,760)	
38	Post-96 Estimated Incremental Revenue Requirement			(1,742,480)	incremental

RNS Rate

The United Illuminating Company
FERC Interest Calculation associated with Under / (Over)
True-up and Interest Calculation for 2011

1 2011 Est. Transmission Revenue Requirements (as billed)	6/11-05/12	Appendix C	21,935,188	70,032,974	ATRR - Prior Year
2 2011 Actual Annual RR			21,720,274	74,377,917	Input Panel Subtotals
3 True-up Over/(Under) (Line 1 - Line 2)			214,914	-4,344,943	

Pre'97
Post'96

Undercollection / (Overcollection)

(\$214,914)
\$4,344,943

Initial Billing Period	Pre 1997 Balance	Post 1996 Balance	FERC Monthly Interest Rate	Pre 1997 Interest	Post 1996 Interest
June 2011	(214,914)	4,344,943	0.27%	(\$580)	\$11,731
July 2011	(215,495)	4,356,675	0.27%	(\$582)	\$11,763
August 2011	(215,495)	4,356,675	0.28%	(\$603)	\$12,199
September 2011	(215,495)	4,356,675	0.27%	(\$582)	\$11,763
October 2011	(217,262)	4,392,399	0.28%	(\$608)	\$12,299
November 2011	(217,262)	4,392,399	0.27%	(\$587)	\$11,859
December 2011	(217,262)	4,392,399	0.28%	(\$608)	\$12,299
January 2012	(219,065)	4,428,856	0.28%	(\$613)	\$12,401
February 2012	(219,065)	4,428,856	0.26%	(\$570)	\$11,515
March 2012	(219,065)	4,428,856	0.28%	(\$613)	\$12,401
April 2012	(220,861)	4,465,173	0.27%	(\$596)	\$12,056
May 2012	(220,861)	4,465,173	0.28%	(\$618)	\$12,502
		Total Interest True-Up		-\$7,162 -\$214,914	\$144,788 \$4,344,943
		Total TU & Int		-\$222,076	\$4,489,731

The United Illuminating Company
PTF Investment By Year
As of 12/31/2011

Year	3530	3540	3550	3560	3570	3580	3520	3500	Pre-97 PTF
1923								4,873.99	4,873.99
1925		53,194.27		29,047.79					82,242.06
1926								169,127.29	169,127.29
1936								18,099.06	18,099.06
1937								20,958.14	20,958.14
1941	226.13						-		226.13
1942	17,480.41	229,476.46		9,590.14	185,294.38		242.72		442,084.11
1944								243.70	243.70
1947	(14,020.80)						14,088.62		67.82
1948	1.59								1.59
1949	1,570.54						606.72	323.21	2,500.47
1950						442.92			442.92
1952	150.82						787.78	8,459.58	9,398.18
1953		6,813.27					1,136.94	12,799.20	20,749.41
1954	123,773.77	64,630.55		3,548.97			5,945.65	792.76	198,691.69
1955	3,660.41	20,335.11		478.23			1,633.84	2,459.97	28,567.57
1956	166.25						375.30		541.55
1957	279.16						3,234.79		3,513.96
1958	506,280.69	36,281.88		3,843.89	53,354.69		45,102.69	21,636.62	666,500.46
1959	140,864.37	38,759.65		76,362.51			2,921.40	127,485.89	386,393.82
1960	197,277.19						9,409.49	25,587.14	762,422.33
1961	110,068.17	392,981.98		132,082.43	533,659.12	489,080.27	14,452.00	223,711.26	1,896,035.22
1962	90,759.99	264,510.32		201,744.96		329.55	1,506.15	105,942.58	664,793.56
1963	69,211.56	77,818.49		14,813.88	957.05		12,585.19	26,967.28	202,353.45
1964	116,476.61	763.19		1,441.57			8,747.19	669.35	128,097.91
1965	139,541.15			1,689.01			4,336.50	-	145,566.66
1966	767,847.51	758,669.73		631,547.86	529,545.19	488,886.62	56,562.25	37,800.58	3,270,859.74
1967	424.09	971.83					3,521.75	33,118.75	38,036.42
1968	314,497.04	109,517.30	213,067.23	136,209.24	3,829.12	5,113.27	214,720.35	223,781.55	1,220,735.10
1969	1,309,918.99		1,956.12	548.85	2,165.29	1,061,216.21	106,804.43	187,953.07	2,670,562.96
1970	102,835.20		1,573.96	6,529.20	60,559.12	85,538.57	13,542.89	3,448.56	274,027.51
1971	699,544.02			4,191.55		3,152.46	22,758.52	-	729,646.55
1972	259,935.43			60,000.00			10,704.39	(949.27)	329,690.54
1973	1,605,696.85	163,137.28	2,175,313.07	809,883.37			128,046.64	364,678.08	5,246,755.29
1974	4,676,249.82	2,354.29	2,716,632.00	733,053.93		59,635.26	289,724.60	(865.59)	8,476,784.31
1975	218,015.25		41,426.49	10,957.97			44,828.90	288,857.60	604,086.20
1976	63,281.77	15.39					738.33	2,120.24	66,155.73
1977	8,225.77	81,979.29		210,621.90				-	300,826.96
1978	620,306.74		4,742,480.25	406,040.48				-	5,768,827.47
1979	6,907.25			38,716.77					45,624.02
1980	2,247.49		118,029.43	59,419.37					179,696.29
1981	170,411.64		415,774.29	38,962.55	5,675.72		42,006.40	22,748.60	695,579.20
1982	81,091.62		112,048.03				13,919.56	-	207,059.21
1983	26,402.57		1,560.04	60,682.30				11,014.88	99,659.79
1984	45,460.18			7,276.18			3,308.24		56,044.60
1985	126,862.94					25,600.45		58,180.04	210,643.43
1986	98,912.30								98,912.30
1987	87,436.43								87,436.43
1988	25,322.11							5,060.23	30,382.34
1989	3,882,048.98	65,160.06		5,967,775.22		1,380,105.84	675,694.57		11,970,784.67
1990	1,519,402.31	3,463,931.03		648,391.20			4,364.86		5,636,089.40
1991	2,674,078.82				851,782.51	7,256,907.43			10,782,768.76
1992	4,763,526.71				65,673.56	690,674.29	1,162,479.56	1,447,782.49	8,130,136.61
1993	4,114,553.07					103,466.78	119,946.43		4,337,966.28
1994	3,042,142.86	1,306,048.20	8,919,373.29	2,886,757.08		108,766.34	76,482.72		16,339,570.49
1995	9,560,961.22	301,344.42	866,352.49	931,130.83	13,967.63	77,322.69	906,502.84	2,450,707.22	15,108,289.33
1996	176,676.40	38,736.22		105,736.31			79,105.14	8,109.18	408,363.25
Pre-97 PTF	42,554,991.41	7,477,430.21	20,325,586.69	14,229,075.54	2,564,991.19	12,107,859.64	4,102,876.31	5,913,683.24	109,276,494.23

Year	3530	3540	3550	3560	3570	3580	3520	3500	Post-1996 PTF
1997	763,213.89	-	-	5,944.10	-	96,292.33	1,343,022.85	-	2,208,473.16
1998	962,836.72	911,471.30	-	17,796.92	-	-	150,544.01	-	2,042,648.95
1999	-	-	-	-	-	-	-	-	-
2000	433,823.56	668,343.63	-	66,708.68	-	-	73,537.45	-	1,242,413.32
2001	872,317.34	-	-	-	-	-	69,410.16	-	941,727.50
2002	897,805.68	1,420,331.53	-	42,626.88	-	-	-	-	2,360,764.09
2003	1,120,767.14	-	-	-	-	-	-	-	1,120,767.14
2004	2,828,898.79	-	-	1,288,165.27	-	1,162,351.51	194,292.73	-	5,473,708.30
2005	1,491,415.12	193,047.80	3,345.36	69,186.73	418,250.14	789,022.26	7,276.10	-	2,971,543.51
2006	2,546,576.06	191,585.67	-	21.00	6,839.28	-	29,433.28	-	2,774,455.29
2007	1,150,664.73	76,169.30	-	171,828.57	-	-	133,101.26	2,791.47	1,534,555.33
2008	130,838,287.61	-	-	233,733.67	102,833,637.71	47,651,804.76	14,058,154.44	1,163,744.17	296,779,362.36
2009	2,124,197.71	886,014.40	-	(0.00)	-	-	2,481,473.73	-	5,491,685.84
2010	8,588,619.27	-	-	138,798.39	-	-	975,790.80	-	9,703,208.46
2011	36,887,190.66	-	-	12,126.01	-	-	668,906.77	-	37,568,223.44
Post-1996 PTF	191,506,614.28	4,346,963.63	3,345.36	2,046,936.22	103,258,727.13	49,699,470.86	20,184,943.57	1,166,535.64	372,213,536.69

481,490,030.92

Sheet: Input Panel

ISO-New England Inc. Tariff Billing
Annual Transmission Revenue Requirements
Per FERC Electric Tariff No. 3, Section II - Attachment F

Shading denotes an input

Submitted on: 14-May-12

Revenue Requirements for (year): Calendar Year 2011

Customer: Unitil Power Corp.

Customer's NABs Number: 185

Name of Participant responsible for customer's billing: New England Power Company

DUNs number of Participant responsible for customer's billing: 00-695-2881

	Pre-97 Revenue Requirements	Post-97 Revenue Requirements
Total of Attachment F - Sections A through I	= <u>0</u> (a)	<u>0</u> (f)
Total of Attachment F - Section J - Support Revenue	<u>0</u> (b)	<u>0</u> (g)
Total of Attachment F - Section K - Support Expense	<u>120,549</u> (c)	<u>0</u> (h)
Total of Attachment F - Section (L through O)	<u>0</u> (d)	<u>0</u> (i)
Sub Total - Sum (A through I) - J + K + (L through O)	<u>120,549</u> (e)=(a)-(b)+(c)+(d)	<u>0</u> (j)
Forecasted Transmission Revenue Requirements (per Appendix C to Attachment F Implementation Rule)	<u>N/A</u>	<u>N/A</u> (k) Worksheet 1a
Annual True-up (per Appendix C to Attachment F Implementation Rule)	<u>\$0</u> (l)	<u>\$0</u> (m) Worksheet 1c
Adjusted Sub Total - Sum (Sub Total + forecast + True-up)	<u>\$120,549</u> (n) = (e) + (l)	<u>\$0</u> (o)=(j)+(k)+(m)
Annual Revenue Requirements Total = Sum of Pre-97 Revenue Requirements & Post-96 Revenue Requirements Subtotals, Forecasted Revenue Requirements & True-ups (including interest)	<u>\$120,549</u> (p) = (n) + (o)	

Unitil Power Corp.
Annual Revenue Requirements of PTF Facilities
for costs in 2011
PRE-1997

PTF Revenue Requirements

Worksheet 1 of 8

Shading denotes an input

		Attachment F			
		Reference	UPC	Total	Reference
Line No.	I. INVESTMENT BASE	Section:			
1	Transmission Plant	(A)(1)(a)	0	0	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	0	0	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	0	0	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		0	0	
5	Accumulated Depreciation	(A)(1)(d)	0	0	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	0	0	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	0	0	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	0	0	Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		0	0	
10	Prepayments	(A)(1)(h)	0	0	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	0	0	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	0	0	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		0	0	
II. REVENUE REQUIREMENTS					
14	Investment Return and Income Taxes	(A)	0	0	Worksheet 2
15	Depreciation Expense	(B)	0	0	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	0	0	Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)	0	0	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	0	0	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	0	0	Worksheet 4, line 17 column 5
20	Operation & Maintenance Expense	(G)	0	0	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	0	0	Worksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	0	Worksheet 7
24	Transmission Support Expense	(K)	120,549	120,549	Worksheet 7
25	Transmission Related Expense from Generators	(L)	0	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	0	0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	0	0	
28	Transmission Rents Received from Electric Property	(O)	0	0	
29	Total Revenue Requirements (Line 14 thru 28)		120,549	120,549	

Unitil Power Corp.
Annual Revenue Requirements
for costs in 2011

Shading denotes an input

	CAPITALIZATION	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 0	#DIV/0!	0.00%	#DIV/0!	
PREFERRED STOCK	0	#DIV/0!	0.00%	#DIV/0!	#DIV/0!
COMMON EQUITY	0	#DIV/0!	0.00%	#DIV/0!	#DIV/0!
TOTAL INVESTMENT RETURN	\$ 0	#DIV/0!		#DIV/0!	#DIV/0!

Cost of Capital Rate=

(a) Weighted Cost of Capital = #DIV/0!

(b) Federal Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right)}{1} \right) \times \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}}$$

=
$$\left(\frac{\#DIV/0! + (0 + 0)}{1} \right) \times \frac{0.34}{0.34}$$

= #DIV/0!

(c) State Income Tax =
$$\left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec. Exp.}}{\text{PTF Inv. Base}} \right)}{1} \right) + \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}} \times \text{State Income Tax Rate}$$

=
$$\left(\frac{\#DIV/0! + (0 + 0)}{1} \right) + \frac{\#DIV/0!}{0.085} \times 0.085$$

= #DIV/0!

(a)+(b)+(c) **Cost of Capital Rate** = #DIV/0!

(PTF)

INVESTMENT BASE \$ 0 From Worksheet 1

x Cost of Capital Rate #DIV/0!

= Investment Return and Income Taxes 0 To Worksheet 1

Unitil Power Corp.

PTF Revenue Requirements
Worksheet 3 of 8

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors		(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
	<u>Transmission Plant</u>						
1	Transmission Plant			0		0	Line 1, Worksheet 5
2	General Plant	#DIV/0!	(a)	#DIV/0!	#DIV/0!	#DIV/0!	Page 207.83g
3	Total (line 1+2)			#DIV/0!		#DIV/0!	
4	<u>Transmission Plant Held for Future Use</u>	0		0	#DIV/0!	#DIV/0!	Page 214
	<u>Transmission Accumulated Depreciation</u>						
5	Transmission Accum. Depreciation	0		0	#DIV/0!	#DIV/0!	Page 219.23b
6	General Plant Accum.Depreciation	0	(a)	#DIV/0!	#DIV/0!	#DIV/0!	Page 219.25b
7	Total (line 5+6)			#DIV/0!		#DIV/0!	
	<u>Transmission Accumulated Deferred Taxes</u>						
8	Accumulated Deferred Taxes (281-283)	0	(c)	#DIV/0!	#DIV/0!	#DIV/0!	Page 275.2k + 277.9k (d)
9	Accumulated Deferred Taxes (190)	0	(c)	#DIV/0!	#DIV/0!	#DIV/0!	Page 234.8c (d)
10	Total (line 8+9)			#DIV/0!		#DIV/0!	
11	<u>Transmission loss on Reacquired Debt</u>	0	(c)	#DIV/0!	#DIV/0!	#DIV/0!	Page 111.65d
	<u>Other Regulatory Assets</u>						
12	FAS 106	0	(a)	#DIV/0!	#DIV/0!	#DIV/0!	Page 232.30e
13	FAS 109	0	(c)	#DIV/0!	#DIV/0!	#DIV/0!	Page 233.1f - 269.1f (d)
14	Other Regulatory Liabilities (254.DK)	0	(c)	#DIV/0!	#DIV/0!	#DIV/0!	
15	Total (line 12+13+14)	0		#DIV/0!		#DIV/0!	
16	<u>Transmission Prepayments</u>	0	(a)	#DIV/0!	#DIV/0!	#DIV/0!	Page 110.46d*p.200.8.c/p.200.8.b
17	<u>Transmission Materials and Supplies</u>	0		0	#DIV/0!	#DIV/0!	Page 227.8c
18	<u>Cash Working Capital</u>						
19	Operation & Maintenance Expense					0	Worksheet 1, Line 20
20	Administrative & General Expense					0	Worksheet 1, Line 21
21	Transmission Support Expense					120,549	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					120,549	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					15,069	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

(d) Electric Only (Gas Portion Removed)

Unitil Power Corp.

PTF Revenue Requirements
Worksheet 4 of 8

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
<u>Depreciation Expense</u>						
1	0		0	#DIV/0!	#DIV/0!	Page 336.7b
2	0	#DIV/0!	(a) #DIV/0!	#DIV/0!	#DIV/0!	Page 336.9b
3			#DIV/0!		#DIV/0!	
4	0	#DIV/0!	(c) #DIV/0!	#DIV/0!	#DIV/0!	Page 117.58c
5	0	#DIV/0!	(c) #DIV/0!	#DIV/0!	#DIV/0!	Page 266.8f
<u>Property Taxes</u>						
6	0	#DIV/0!	(c) #DIV/0!	#DIV/0!	#DIV/0!	Page 262i-263i (e)
7	0	#DIV/0!	(a) #DIV/0!	#DIV/0!	#DIV/0!	Page 262-263
8			#DIV/0!		#DIV/0!	
<u>Transmission Operation and Maintenance</u>						
9	0		0	#DIV/0!	#DIV/0!	Page 321.100b
10	0		0	#DIV/0!	#DIV/0!	Page 321.88b
11	0		0	#DIV/0!	#DIV/0!	Page 321.84b
12					0	Page 321.85b & .90b
13	0		0	#DIV/0!	#DIV/0!	
<u>Transmission Administrative and General</u>						
14	0					Page 323.168b
15	0					Page 323.156b
16	0					Page 350
17	0					Page 323.162b
18	0	#DIV/0!	(a) #DIV/0!	#DIV/0!	#DIV/0!	
19	0	#DIV/0!	(c) #DIV/0!	#DIV/0!	#DIV/0!	
20	0	#DIV/0!	(c) #DIV/0!	#DIV/0!	#DIV/0!	
21	0	#DIV/0!	(c) #DIV/0!	#DIV/0!	#DIV/0!	
22	0		#DIV/0!		#DIV/0!	
23	0	#DIV/0!	(a) #DIV/0!	#DIV/0!	#DIV/0!	Footnote (d)

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

(d) Payroll taxes FERC Form 1, page 263.i ,263.1i

Federal Unemployment	0
FICA	0
Medicare	0
State Unemployment	0
MA Universal Health	0
Payroll Taxes Capitalized	0

Total 0 To Line 23

(e) Electric Only (Gas Portion Removed)

** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments.

Sheet: Worksheet 5

Shading denotes an input

Line No.			FERC Form 1 Reference
<u>PTF Transmission Plant Allocation Factor</u>		UPC	
1	PTF Transmission Investment	0	See Workpaper 1 Page 207.53g
2	Total Transmission Investment	0	
3	Percent Allocation (Line 1/Line 2)	#DIV/0!	
<u>Transmission Wages and Salaries Allocation Factor</u>			
4	Direct Transmission Wages and Salaries	0	Page 354.19b Worksheet 6 of 8
5	Affiliated Company Transmission Wages and Salaries	0	
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	0	
7	Total Wages and Salaries	0	Page 354.25b + Line 5 Page 354.24b Worksheet 6 of 8
8	Administrative and General Wages and Salaries	0	
9	Affiliated Company Wages and Salaries less A&G	0	
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	0	
11	Percent Allocation (Line 6/Line 10)	#DIV/0!	
<u>Plant Allocation Factor</u>			
12	Total Transmission Investment	0	Page 207.53g Worksheet 3, Line 2
13	plus Transmission-Related General Plant (Line 2 of Wkst. 3)	#DIV/0!	
14	= Revised Numerator (Line 12 + Line 13)	#DIV/0!	
15	Total Plant in Service	0	Page 207.88g
16	Percent Allocation (Line 14 / Line 15)	#DIV/0!	

Affiliated Company Wages and Salaries

Shading denotes an input

Line		UPC	
"Affiliated" Transmission Wages and Salaries #560 - 573			
1	560	0	
2	562	0	
3	564	0	
4	566	0	
5	568	0	
6	569	0	
7	570	0	
8	571	0	
9	572	0	
10	573	0	
11 = 1 thru 10	Total Transmission	0	
12 = Total "Affiliated" Wages and Salaries			
Less "Affiliated" Administrative and General Salaries #920 - 935			
13	920	0	
14	921	0	
15	923	0	
16	925	0	
17	926	0	
18	928	0	
19	930	0	
20	935	0	
21 = 13 thru 20		0	
22 = 12 less 21	Total "Affiliated" less A&G	0	

PTF Revenue Requirements

Worksheet 7 of 8

Sheet: Worksheet 7

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	UPC		TOTAL	
		Revenues (a)	Expenses (b)	Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line				
	115 kV Somerville 402 Substation				
	115/345 kV North Cambridge 509 Substation				
	345 kV Golden Hills -Mystic 389 (x&y) line				
	West Medway 345 kV breaker				
	115 kV Millbury-Medway 201 line				
	HQ Phase II - AC in MA	0	5,574	0	5,574
	345 kV "stabilizer" 342 line				
	345 kV Walpole - Medway 325 line				
	345 kV Carver - Walpole 331 line				
	345 kV Jordan Rd - Canal 342 line				
CEC	Second Canal line				
	345 kV Pilgrim-Bridgewater - 355 line				
	345 kV Myles Standish - Canal 342 line				
CMP	345 kV Buxton-South Gorham 386 line				
	115 kV Wyman 164-167 lines				
	115 kV Maine Yankee transmission				
EUA	345 kV Carver - Walpole 331 line				
	345 kV Medway - Bridgewater 344 Line				
	Northern Rhode Island transmission				
NEP	Chester SVC	0	35,062	0	35,062
	Comerford 115 kV Substation				
	345 kV Sandy-Tewksbury 337 line				
	345 kV Tewksbury-Woburn 338 line				
	115 kV Tewksbury - Woburn M139 line				
	115 kV Tewksbury - Woburn N140 line				
	Moore 115 kV Substation				
	HQ Phase II - AC in MA	0	79,913	0	79,913
	345 kV Golden Hills-Mystic 349 line				
	345 kV NH/MA border-Tewksbury 394 line				
	115 kV Read - Washington V148 line				
NU					
	345 kV 363, 369 and 394 Seabrook lines				
	Fairmont 115 kV Substation				
	345 kV Millstone-Manchester 310 line				
	UI Substations				
	Black Pond				
	Total =	0	120,549	0	120,549

Amount by which Support Expense exceeds Support Revenues 120,549

(To Worksheet 3, Line 21, Column 5)

See Workpaper 1.

Summary of **Unitil Power Corp. System**
Monthly Coincident Peaks for 2011
(Megawatts)

Shading denotes an input

	JAN '11	FEB '11	MAR '11	APR '11	MAY '11	JUN '11	JUL '11	AUG '11	SEP '11	OCT '11	NOV '11	DEC '11
Day	0	0	0	0	0	0	0	0	0	0	0	0
Hour	0:00	0:00	0:00	0:00	0:00	0:00	0:00	0:00	0:00	0:00	0:00	0:00
UPC	-	-	-	-	-	-	-	-	-	-	-	-
Annual UPC System Average 12 CP Load												0

NOTE: Numbers represent FERC Form 1 Pages 401/401A coincident peaks.

Workpaper 1
Unitil Power Corp
Transmission Support Payment Accounts

2011

13-20-13-00-565-11-01	HQ - BECO AC (d/b/a NSTAR)	5,574.07	
13-20-13-00-565-46-00	HQ II TRANS EXP - BECO	\$ -	
	Total	\$ 5,574.07	Worksheet 7, BECo HQ Phase II - AC in MA
13-20-13-00-565-11-02	HQ - NEP AC	79,913.14	Worksheet 7, NEP HQ Phase II - AC in MA
13-20-13-00-565-11-03	HQ - Chester SVC	35,062.15	Worksheet 7, NEP Chester SVC

ISO-NE Tariff Billing									
PTO Annual Transmission Revenue Requirements									
per OATT Attachment F									
Submitted on:						May 14, 2012			
Revenue Requirements for (test year):						Calendar Year 2011			
Rates Effective for the period:						June 1, 2012			
through:						May 31, 2013			
Customer:						VT TRANSCO LLC			
Customer's NABs Number:						52			
Name of Participant responsible for customer's billing:						VT TRANSCO LLC			
DUNs number of Participant responsible for customer's billing:						78-0399163			
						Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	=	\$	10,960,665	(a)			\$	101,502,329	(f)
Total of Attachment F - Section J - Support Revenue			-	(b)				-	(g)
Total of Attachment F - Section K - Support Expense			975,979	(c)				-	(h)
Total of Attachment F - Section (L through O)			48,556	(d)				454,518	(i)
Sub Total - Sum (A through I) - J + K + (L through O)			11,985,200	(e)=(a)-(b)+(c)+(d)				101,956,847	(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)			N/A					7,028,376	(k)
Annual True-up (per Attachment C to Attachment F Implementation Rule)			367,045	(l)				5,838,758	(m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)		\$	12,352,245	(n)=(e)+(l)			\$	114,823,981	(o)=(j)+(k)+(m)
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements & Post-96 Revenue Requirements Subtotals, Forecasted Revenue Requirements, and True-ups (including interest)									
						\$	127,176,226	(p) = (n)+(o)	

VT TRANSCO AND Bennington Searsburg Line									
Annual Revenue Requirements of PTF Facilities									
2011									
			Attachment F	PRE 97	POST 1996	TOTAL			
			Reference						Ref
	I. INVESTMENT BASE		Section:						
Line No.									
1	Transmission Plant	(A)(1)(a)	\$ 61,906,556	\$ 565,827,989	\$ 627,734,544				Worksheet 1
2	General Plant	(A)(1)(b)	5,319,527	49,409,327	54,728,854				Worksheet 1
3	Plant Held For Future Use	(A)(1)(c)	96	-	96				Worksheet 1
4	Total Plant (Lines 1+2+3)		67,226,179	615,237,316	682,463,494				
5	Accumulated Depreciation	(A)(1)(d)	10,336,081	91,186,237	101,522,318				Worksheet 1
6	Accumulated Deferred Income Taxes	(A)(1)(e)	4,678,799	41,946,951	46,625,750				Worksheet 1
7	Loss On Reacquired Debt	(A)(1)(f)	-	-	-				Worksheet 1
8	Other Regulatory Assets	(A)(1)(g)	1,337	-	1,337				Worksheet 1
9	Net Investment (Line 4-5-6+7+8)		52,212,636	482,104,128	534,316,763				
10	Prepayments	(A)(1)(h)	144,392	1,219,654	1,364,046				Worksheet 1
11	Materials & Supplies	(A)(1)(i)	619,736	5,598,102	6,217,838				Worksheet 1
12	Cash Working Capital	(A)(1)(j)	288,617	1,387,327	1,675,944				Worksheet 1
13	Total Investment Base (Line 9+10+11+12)		\$ 53,265,381	\$ 490,309,211	\$ 543,574,591				Worksheet 1
	II. REVENUE REQUIREMENTS								
14	Investment Return and Income Taxes	(A)	\$ 6,935,739	\$ 65,943,708	\$ 72,879,447				Worksheet 1
15	Depreciation Expense	(B)	1,541,121	14,082,160	15,623,281				Worksheet 1
16	Amortization of Loss on Reacquired Debt	(C)	-	-	-				Worksheet 1
17	Investment Tax Credit	(D)	(574)	-	(574)				Worksheet 1
18	Property Tax Expense	(E)	1,068,971	9,632,183	10,701,154				Worksheet 1
19	Payroll Tax Expense	(F)	82,450	745,661	828,111				
20	Operation & Maintenance Expense	(G)	739,188	5,935,605	6,674,793				Worksheet 1
21	Administrative & General Expense	(H)	593,770	5,163,012	5,756,782				Worksheet 1
22	Transmission Related Integrated Facilities Charge	(I)	-	-	-				Worksheet 1
23	Transmission Support Revenue	(J)	-	-	-				Worksheet 1
24	Transmission Support Expense	(K)	975,979	-	975,979				Worksheet 1
25	Transmission Related Expense from Generators	(L)	-	-	-				
26	Transmission Related Taxes and Fees Charge	(M)	52,345	489,987	542,332				
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(2,229)	(20,868)	(23,097)				Worksheet 1
28	Transmission Rents Received from Electric Property	(O)	(1,560)	(14,600)	(16,160)				
29	Total RNS Revenue Requirements before Forecast, Annual True-up and Assoc. Interest (Line 14 thru 28)		\$ 11,985,200	\$ 101,956,847	\$ 113,942,048				

VT TRANSCO and Bennington Searsburg Line							
Transmission Revenue Requirements of PTF Facilities							
2011 True-up							
	I.	APPENDIX C - ANNUAL TRUE-UP	Rate Year	PRE97	POST 1996	Total	Reference
1		ATRR for True-up = 2011 Actual	6/1/12-5/31/13	\$ 11,985,200	\$ 101,956,847	\$ 113,942,048	Summary 6-1-12_5-31-13, line 29
2		ATRR subject to True-up = '10 TY + '11 Forecast -	6/1/11-5/31/12	11,450,906	96,306,382	107,757,288	Summary 6-1-11_5-31-12, line 31
3		Annual True-up (Line 1 - Line 2)		\$ 534,294	\$ 5,650,466	\$ 6,184,760	

[illegible]

VT TRANSCO
FERC Interest Calculation associated with Under / (Over)
Transmission Revenue Requirements of PTF Facilities
Bennington Searsburg Line Per FERC Audit
Docket No. FA11-16-000

(Overcollection):

Pre-97	2005	(5,917)	
	2006	(17,086)	
	2007	(23,826)	
	2008	(51,813)	
	2009	(23,143)	
	2010	<u>(44,739)</u>	
		(166,524)	Per FERC Audit Docket No. FA11-16-000

<u>Initial Billing Period</u>		<u>FERC Monthly Interest Rate</u>	
June 2006	(5,917)	0.60%	\$ (35.50)
July 2006	(5,953)	0.66%	(39.29)
August 2006	(5,953)	0.66%	(39.29)
September 2006	(5,953)	0.64%	(38.10)
October 2006	(6,069)	0.69%	(41.88)
November 2006	(6,069)	0.67%	(40.66)
December 2006	(6,069)	0.69%	(41.88)
January 2007	(6,194)	0.70%	(43.36)
February 2007	(6,194)	0.63%	(39.02)
March 2007	(6,194)	0.70%	(43.36)
April 2007	(6,319)	0.68%	(42.97)
May 2007	(6,319)	0.70%	(44.24)
June 2007	(23,493)	0.68%	(159.75)
July 2007	(23,652)	0.70%	(165.57)
August 2007	(23,652)	0.70%	(165.57)
September 2007	(23,652)	0.68%	(160.84)
October 2007	(24,144)	0.70%	(169.01)
November 2007	(24,144)	0.68%	(164.18)
December 2007	(24,144)	0.70%	(169.01)
January 2008	(24,646)	0.66%	(162.67)
February 2008	(24,646)	0.62%	(152.81)
March 2008	(24,646)	0.66%	(162.67)
April 2008	(25,125)	0.56%	(140.70)
May 2008	(25,125)	0.57%	(143.21)
June 2008	(49,234)	0.56%	(275.71)
July 2008	(49,510)	0.45%	(222.80)
August 2008	(49,510)	0.45%	(222.80)
September 2008	(49,510)	0.44%	(217.84)
October 2008	(50,174)	0.42%	(210.73)
November 2008	(50,174)	0.41%	(205.71)
December 2008	(50,174)	0.42%	(210.73)
January 2009	(50,801)	0.38%	(193.04)
February 2009	(50,801)	0.34%	(172.72)
March 2009	(50,801)	0.28%	(142.24)
April 2009	(51,309)	0.28%	(143.66)
May 2009	(51,309)	0.29%	(148.80)
June 2009	(103,414)	0.28%	(289.56)
July 2009	(103,704)	0.28%	(290.37)
August 2009	(103,704)	0.28%	(290.37)
September 2009	(103,704)	0.27%	(280.00)
October 2009	(104,565)	0.28%	(292.78)
November 2009	(104,565)	0.27%	(282.32)
December 2009	(104,565)	0.28%	(292.78)
January 2010	(105,432)	0.28%	(295.21)
February 2010	(105,432)	0.25%	(263.58)
March 2010	(105,432)	0.28%	(295.21)
April 2010	(106,286)	0.27%	(286.97)
May 2010	(106,286)	0.28%	(297.60)
June 2010	(130,014)	0.27%	(351.04)
July 2010	(130,365)	0.28%	(365.02)
August 2010	(130,365)	0.28%	(365.02)
September 2010	(130,365)	0.27%	(351.99)
October 2010	(131,447)	0.28%	(368.05)
November 2010	(131,447)	0.27%	(354.91)
December 2010	(131,447)	0.28%	(368.05)
January 2011	(132,538)	0.28%	(371.11)
February 2011	(132,538)	0.25%	(331.35)
March 2011	(132,538)	0.28%	(371.11)
April 2011	(133,612)	0.27%	(360.75)
May 2011	(133,612)	0.28%	(374.11)
June 2011	(179,086)	0.27%	(483.53)
July 2011	(179,569)	0.27%	(484.84)
August 2011	(179,569)	0.28%	(502.79)
September 2011	(179,569)	0.27%	(484.84)
October 2011	(181,042)	0.28%	(506.92)
November 2011	(181,042)	0.27%	(488.81)
December 2011	(181,042)	0.28%	(506.92)
January 2012	(182,544)	0.28%	(511.12)
February 2012	(182,544)	0.26%	(474.61)
March 2012	(182,544)	0.28%	(511.12)
April 2012	(184,041)	0.27%	(496.91)
May 2012	(184,041)	0.28%	<u>(515.31)</u>

Total Interest	\$	(18,529)	
Plus Refund		<u>(166,524)</u>	
		<u>(185,053)</u>	Overcollection

NEPOOL Tariff Billing
NEPOOL Annual Transmission Revenue Requirements
per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3
Bennington - Searsburg Line owned by CVPS PTF Facility

Shading denotes an input

TOTAL

Submitted on: May 14, 2012 RTO ROE filing

Revenue Requirements for (year): Calendar Yr 2011 \$ 323,587

Customer: VT TRANSCO LLC

Customer's NABs Number: 52

Name of Participant responsible for customer's billing: VT TRANSCO LLC

DUNS number of Participant responsible for customer's billing: 78-0399163

	<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>
Total of Attachment F - Sections A through I =	<u>323,588</u> (a)	<u> </u> (f)
Total of Attachment F - Section J - Support Revenue	<u>0</u> (b)	<u> </u> (g)
Total of Attachment F - Section K - Support Expense	<u>0</u> (c)	<u> </u> (h)
Total of Attachment F - Section (L through O)	<u>(1)</u> (d)	<u> </u> (i)
Sub Total - Sum (A through I) - J + K + (L through O)	<u>323,587</u> (e)=(a)-(b)+(c)+(d)	<u>-</u> (j)

Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:

323,587 (k) = (e) + (j)

Total of Attachment F - Section J - Pre-97 Support Revenue (from above)	<u>0</u> (b)
Total of Attachment F - Section J - Post-96 Support Revenue (from above-)	<u>0</u> (g)
Total of Attachment F - Section K - Post-96 Support Expense (from above)	<u>0</u> (h)

Voting Share Total for Participant's R Value: 323,587 (l)=(k)+(b)+(g)-(h)

(for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)

Annual Revenue Requirements of PTF Facilities
for costs in 2011

PTF Revenue Requirements
Worksheet 1 of 8

Shading denotes an input

		Attachment F		
		Reference	##	Reference
Line N		Total		
I. INVESTMENT BASE		Section:		
1	Transmission Plant	(A)(1)(a)	1,459,049	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	41,141	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	96	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		1,500,286	
5	Accumulated Depreciation	(A)(1)(d)	594,678	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	197,617	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	0	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	1,337	Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		709,328	
10	Prepayments	(A)(1)(h)	14,097	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	21,692	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	18,412	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		763,529	
II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	97,383	Worksheet 2
15	Depreciation Expense	(B)	36,727	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	0	Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)	(574)	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	39,967	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	2,791	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	(G)	105,088	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	42,206	Worksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	0	Worksheet 7
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)		
27	Revenue for ST Trans. Service Under NEPOOL	(N)		
28	Transmission Rents Received from Electric Prop	(O)		
29	Total Revenue Requirements (Line 14 thru 28)		323,588	

**Annual Revenue Requirements
for costs in 2011**

Shading denotes an input

	CAPITALIZATION 12/31/2011	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 240,578,319	46.55%	5.70%	2.65%	
PREFERRED STOCK	8,053,800	1.56%	4.90%	0.00%	0.00%
COMMON EQUITY	268,152,973	51.90%	11.64%	6.04%	6.04%
TOTAL INVESTMENT	\$ 516,785,092	100.01%		8.69%	6.04%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0869

$$\begin{aligned}
 \text{(b) Federal Income Tax Rate} &= \frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Depreciation}}{\text{PTF Inv. Base}} \right) \times \text{Federal Income Tax Rate}}{1 - \text{Federal Income Tax Rate}} \\
 &= \frac{0.0604 + \left(\frac{(574) + 0}{763,529} \right) \times 0.35}{1 - 0.35} \\
 &= \underline{\underline{0.0321183}}
 \end{aligned}$$

$$\begin{aligned}
 \text{(c) State Income Tax Rate} &= \frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Depreciation}}{\text{PTF Inv. Base}} \right) + \text{Federal Income Tax Rate}}{1 - \text{State Income Tax Rate}} \times \text{State Income Tax Rate} \\
 &= \frac{0.0604 + \left(\frac{(574) + 0}{763,529} \right) + 0.0321183}{1 - 0.085} \times 0.085 \\
 &= \underline{\underline{0.0085248}}
 \end{aligned}$$

(a)+(b)+(c) **Cost of Capital** = 0.1275431

(PTF)

INVESTMENT BASE \$ 763,529 From Worksheet 1

x Cost of Capital Rate 0.1275431

= Investment Return and 97,383 To Worksheet 1

Sheet: Worksheet 3

Shading denotes an input

Line No.	(1) Total	fo (2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
<u>Transmission Plant</u>						
1	79,812,164		79,812,164		1,459,049	Line 1, Worksheet 5
2	40,752,123	5.5224% (a)	2,250,498	1.8281%	41,141	Page 207.99g
3			82,062,662		1,500,190	
4	42,819	12.3088%	5,271	1.8281%	96	Page 214.47d
<u>Transmission Accumulated Depreciation</u>						
5	31,410,082		31,410,082	1.8281%	574,208	Page 219.25b
6	20,276,798	5.5224% (a)	1,119,767	1.8281%	20,470	Page 219.28b
7			32,529,849		594,678	
<u>Transmission Accumulated Deferred Taxes</u>						
8	124,808,708	12.3088% (c)	15,362,454	1.8281%	280,841	Page 113.(62-64)c
9	(36,985,753)	12.3088% (c)	(4,552,502)	1.8281%	(83,224)	Page 111.82c
10			10,809,952		197,617	
11	0	12.3088% (c)	0	1.8281%	0	Page 111.81d
<u>Other Regulatory Assets</u>						
12	0	5.5224% (a)	0	1.8281%	0	Page 232.30e
13	4,722,061	12.3088% (c)	581,229	1.8281%	10,625	Page 232.11f
14	(4,127,877)	12.3088% (c)	(508,092)	1.8281%	(9,288)	Page 278.1e
15	594,184		73,137		1,337	
16	13,963,831	5.5224% (a)	771,139	1.8281%	14,097	Page 111.57c
17	1,186,573		1,186,573	1.8281%	21,692	Page 227.8c
<u>Cash Working Capital</u>						
19					105,088	Worksheet 1, Line 20
20					42,206	Worksheet 1, Line 21
21					0	Worksheet 1, Line 24
22					147,294	
23					0.125	x 45 / 360
24					18,412	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

Shading denotes an input

Line No.		(2)		(4)		FERC Form 1 Reference for col (1)
		(1) Total	for costs in 2005 Wage/Plant Allocation Factors	PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	
	<u>Depreciation Expense</u>					
1	Transmission Depreciation	1,821,112		1,821,112	1.8281%	33,292
2	General Depreciation	3,402,228	5.5224% (a)	187,885	1.8281%	3,435
3	Total (line 1+2)			2,008,997		36,727
4	<u>Amortization of Loss on Reacquired Deb</u>	0	(c)	1.8281%	0	Page 117.64c
5	<u>Amortization of Investment Tax Credit</u>	255,022	12.3088% (c)	31,390	1.8281%	574
	<u>Property Taxes *</u>					
6	Transmission Property Taxes	12,260,936	12.3088% (c)	1,509,174	1.8281%	27,589
7	General Property Taxes	12,260,936	5.5224%	677,099	1.8281%	12,378
8	Total (line 6+7)			2,186,273		39,967
	<u>Transmission Operation and Maintenance</u>					
9	Operation and Maintenance	40,207,693		40,207,693	1.8281%	735,037
10	Transmission of Electricity by Others - #565	34,393,687		34,393,687	1.8281%	628,751
11	Load Dispatching - #561	65,511		65,511	1.8281%	1,198
12	**Station Expenses & Rents - #562 / #567	0		0	1.8281%	0
13	O&M less lines 10, 11 & 12	5,748,495		5,748,495		105,088
	<u>Transmission Administrative and General</u>					
14	Administrative and General	38,873,721				Page 323.197b
15	less Property Insurance (#924)	843,344				Page 323.185b
16	less Regulatory Commission Expenses (#928)	1,543,557				Page 323.189b
17	less General Advertising Expense (#930.1)	0				Page 323.191b
18	Subtotal [line 14 minus (15 thru 17)]	36,486,820	5.5224% (a)	2,014,950	1.8281%	36,835
19	PLUS Property Insurance alloc. using Plant Allocation	843,344	12.3088% (c)	103,806	1.8281%	1,898
20	PLUS Regulatory Comm. Exp. (FERC Assessments)	1,543,557	12.3088% (c)	189,993	1.8281%	3,473
21	PLUS Trans. Related General Advertising Expense	0	12.3088% (c)	0	1.8281%	0
22	Total A&G [line 18 plus (19 thru 21)]	38,873,721		2,308,749		42,206
23	<u>Payroll Tax Expense</u>	2,764,903	5.5224% (a)	152,689	1.8281%	2,791

* Property Taxes functionalized per FERC Form 1; therefore, no need to use Plant Allocation Factor

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

(d) Payroll taxes FERC Form 1, page 263.i, 263.1

Federal Unemployment	24,571
FICA	2,591,007
Medicare	0
CT Unemployment	
MA Unemployment	
MA Universal Health	
VT Unemployment	149,325
NH Unemployment	0
Total	2,764,903

To Line 23

** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments

Shading denotes an input

Line
No.

FERC Form 1
Reference

PTF Transmission Plant Allocation Factor

1	PTF Transmission Investment	1,459,049	NEPOOL Catalog Bennington Searsburg Line
2	Total Transmission Investment	79,812,164	Page 207.58g
		0	
3	Percent Allocation (Line 1/Line 2)	1.8281%	

Transmission Wages and Salaries Allocation Factor

4	Direct Transmission Wages and Salaries	1,379,864	Page 354.21b
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 & 6a of 8
6	Total Transmission Wages and Salaries (Line 4 +	1,379,864	
7	Total Wages and Salaries	37,440,863	Page 354.28b
8	Administrative and General Wages and Salaries	12,454,216	Page 354.27b
9	Affiliated Company Wages and Salaries less A&G	0	Worksheet 6 & 6a of 8
10	Total Wages and Salaries net of A&G (Line 7 - 8	24,986,647	
11	Percent Allocation (Line 6/Line 10)	5.5224%	

Plant Allocation Factor

12	Total Transmission Investment	79,812,164	Page 207.58g
13	plus Transmission-Related General Plant (Line 2 of W	2,250,498	Page 207.99g
14	= Revised Numerator (Line 12 + Line 13)	82,062,662	
15	Total Plant in Service	666,698,283	Page 207.104g
16	Percent Allocation (Line 14 / Line 15)	12.3088%	

Input Revenues associated with the PTF Supporting Facilities in columns (a) and (b) with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines

Participant	PTF Supporting Facilities	FERC Form 1	TOTAL	
			Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	32.(g); [332.1(g) for HWP]		
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			
	Comerford 115 kV Substation			
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	32.1(g); [332(g) for CL&P]		
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury	332(g)		
	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310	330.1(n)		
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
Total =			0	0

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

NEPOOL Tariff Billing
NEPOOL Annual Transmission Revenue Requirements
per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3

Shading denotes an input

TOTAL

Submitted on:	May 14, 2012
Revenue Requirements for (year):	Calendar Yr 2011 \$ 126,852,638
Customer:	VT TRANSCO LLC
Customer's NABs Number:	52
Name of Participant responsible for customer's billing:	VT TRANSCO LLC
DUNS number of Participant responsible for customer's billing:	78-0399163

	Pre-97 Revenue Requirements	Post-96 Revenue Requirements
Total of Attachment F - Sections A through I =	10,637,077 (a)	101,502,329 (f)
Total of Attachment F - Section J - Support Revenue	0 (b)	(g)
Total of Attachment F - Section K - Support Expense	975,979 (c)	(h)
Total of Attachment F - Section (L through O)	48,556 (d)	454,518 (i)
Sub Total - Sum (A through I) - J + K + (L through O)	11,661,612 (e)=(a)-(b)+(c)+(d)	101,956,847 (j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	N/A	7,028,376 (k) = (e) + (j)
Annual True-up (per Attachment C to Attachment F Implementation Rule)	\$367,045 (l)	\$5,838,758 (m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)	12,028,657 (n)=(e)+(l)	114,823,981 (o)=(j)+(k)+(m)
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements & Post-96 Revenue Requirements Subtotals, Forecasted Revenue Requirements and True-ups (including interest)		<u>126,852,638</u> (p)=(n)+(o)

VT TRANSCO
Annual Revenue Requirements of PTF Facilities
for costs in 2011

PTF Revenue Requirements

Worksheet 1 of 8

Shading denotes an input

		Attachment F	
		Reference	Total
Line N	I. INVESTMENT BASE	Section:	
1	Transmission Plant	(A)(1)(a)	626,275,495
2	General Plant	(A)(1)(b)	54,687,782 Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	0 Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		680,963,277
5	Accumulated Depreciation	(A)(1)(d)	100,927,765 Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	46,428,191 Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	0 Worksheet 3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	0 Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		533,607,321
10	Prepayments	(A)(1)(h)	1,349,951 Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	6,196,153 Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	1,657,535 Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		542,810,960
II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	70,701,019 Worksheet 2
	Investment Return and Income Taxes		2,081,030 Worksheet adder
15	Depreciation Expense	(B)	15,586,573 Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	0 Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)	0 Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	10,661,200 Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	825,321 Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	(G)	6,569,713 Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	5,714,584 Worksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0 Worksheet 7
23	Transmission Support Revenue	(J)	0 Worksheet 7
24	Transmission Support Expense	(K)	975,979 Worksheet 7
25	Transmission Related Expense from Generators	(L)	0 Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	542,298 Gross Revenue Tax
27	Revenue for ST Trans. Service Under NEPOOL	(N)	(23,097) Schedule 8 TOUT Revenues
28	Transmission Rents Received from Electric Prop	(O)	(16,160) Rev Rent 4000-454122
29	Total Revenue Requirements (Line 14 thru 28)		113,618,459

VT TRANSCO
Annual Revenue Requirements
for costs in 2011

Shading denotes an input

	CAPITALIZATION 12/31/11	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 317,272,000	45.47%	5.52%	2.51%	
PREFERRED STOCK	0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	380,424,246	54.54%	11.64%	6.35%	6.35%
TOTAL INVESTMENT	\$ 697,696,246	100.01%		8.86%	6.35%

Cost of Capital Rate=

(a) Weighted Cost c = 0.0886

(b) Federal Income =
$$\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Depre}}{\text{PTF Inv. Base}} \right)}{1} \times \frac{\text{Federal Income Tax Rate}}{1 - \text{Federal Income Tax Rate}}$$

=
$$\frac{0.0635 + \frac{0 + 0}{542,810,960}}{1} \times \frac{0.34}{1 - 0.34}$$

= 0.0327121

(c) State Income Tax =
$$\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Depre}}{\text{PTF Inv. Base}} \right)}{1} + \frac{\text{Federal Income Tax}}{1 - \text{State Income Tax Rate}} \times \text{State Income Tax Rate}$$

=
$$\frac{0.0635 + \frac{0 + 0}{542,810,960}}{1} + \frac{0.0327121}{1 - 0.085} \times 0.085$$

= 0.0089377

(a)+(b)+(c) **Cost of** = 0.1302498

(PTF)

INVESTMENT BASE \$ 542,810,960 From Worksheet 1

x Cost of Capital Rate 0.1302498

= Investment Return and 70,701,019 To Worksheet 1

Sheet: Worksheet 3

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col
<u>Transmission Plant</u>						
1	780,225,984		780,225,984		626,275,495	Line 1, Worksh
2	68,131,062	100.0000% (a)	68,131,062	80.2685%	54,687,782	Page 207.99g
3	Total (line 1+2)		<u>848,357,046</u>		<u>680,963,277</u>	
4	<u>Transmission Plant Held for Future Use</u>		0	80.2685%	0	Page 214.47d
<u>Transmission Accumulated Depreciation</u>						
5	105,480,405		105,480,405	80.2685%	84,667,539	Page 219.25b
6	20,257,294	100.0000% (a)	20,257,294	80.2685%	16,260,226	Page 219.27b
7	Total (line 5+6)		<u>125,737,699</u>		<u>100,927,765</u>	
<u>Transmission Accumulated Deferred Taxes</u>						
8	(58,259,823)	99.2813% (c)	(57,841,110)	80.2685%	(46,428,191)	Page 113.63d
9	0	99.2813% (c)	0	80.2685%	0	Page 111.68d
10	Total (line 8+9)		<u>(57,841,110)</u>		<u>(46,428,191)</u>	
11	<u>Transmission loss on Reacquired Debt</u>	99.2813% (c)	0	80.2685%	0	Page 111.81d
<u>Other Regulatory Assets</u>						
12	0	100.0000% (a)	0	80.2685%	0	Page 232.30e
13	0	99.2813% (c)	0	80.2685%	0	Page 232.21&2
14	0	99.2813% (c)	0	80.2685%	0	Page 278.1e
15	<u>0</u>		<u>0</u>		<u>0</u>	
16	1,681,794	100.0000% (a)	1,681,794	80.2685%	1,349,951	Page 111.57c
17	7,719,284		7,719,284	80.2685%	6,196,153	Page 227.8c
<u>Cash Working Capital</u>						
19					6,569,713	Worksheet 1, L
20					5,714,584	Worksheet 1, L
21					975,979	Worksheet 1, L
22					13,260,276	
23					0.125	x 45 / 360
24					<u>1,657,535</u>	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

Sheet: Worksheet 4

		(2)			(4)		
Shading denotes an input							
Line No.		(1) Total	Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
	<u>Depreciation Expense</u>						
1	Transmission Depreciation	15,707,503		15,707,503	80.2685%	12,608,177	Page 336.7b
2	General Depreciation	3,710,542	100.0000% (a)	3,710,542	80.2685%	2,978,396	Page 336.9b
3	Total (line 1+2)			19,418,045		15,586,573	
4	Amortization of Loss on Reacquired	0	99.2813% (c)	0 C	80.2685%	0	Page 117.64c
5	Amortization of Investment Tax Credits		99.2813% (c)	0	80.2685%	0	Page 266.8f
	<u>Property Taxes *</u>						
6	Transmission Property Taxes	13,281,923	99.2813% (c)	13,281,923	80.2685%	10,661,200	Page 262-263 FN.1-2
7	General Property Taxes			0	80.2685%	0	Page 262-263 FN.1-2
8	Total (line 6+7)			13,281,923		10,661,200	
	<u>Transmission Operation and Maintenance</u>						
9	Operation and Maintenance	11,811,480		11,811,480	80.2685%	9,480,898	Page 321.112b
10	Transmission of Electricity by Others	473,135		473,135	80.2685%	379,778	Page 321.96b
11	Load Dispatching - #561.1-561.4	3,102,815		3,102,815	80.2685%	2,490,583	Page 321.84 - 88b
12	**Station Expenses & Rents - #562 / #567	50,860		50,860	80.2685%	40,824	Page 321.93b & .98b
13	O&M less lines 10, 11 & 12	8,184,670		8,184,670		6,569,713	
	<u>Transmission Administrative and General</u>						
14	Administrative and General	7,128,490					Page 323.197b
15	less Property Insurance (#924)	675,526					Page 323.185b
16	less Regulatory Commission Expenses (#928)	299,593					Page 323.189b
17	less General Advertising Expense (#930.1)	298,697					Page 323.191b
18	Subtotal [line 14 minus (15 thru 17)]	5,854,674	100.0000% (a)	5,854,674	80.2685%	4,699,459	
19	PLUS Property Insurance alloc. using Plant Allocat.	675,526	99.2813% (c)	670,671	80.2685%	538,338	
20	PLUS Regulatory Comm. Exp. (FERC Assessments)	299,593	99.2813% (c)	297,440	80.2685%	238,751	
21	PLUS Trans. Related General Advertising Expense	298,697	99.2813% (c)	296,550	80.2685%	238,036	
22	Total A&G [line 18 plus (19 thru 21)]	7,128,490		7,119,335		5,714,584	
23	Payroll Tax Expense	1,028,200	100.0000% (a)	1,028,200	80.2685%	825,321	Footnote (d)

* Property Taxes functionalized per FERC Form 1; therefore, no need to use Plant Allocation Factor

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

(d) Payroll taxes FERC Form 1, page 263.i ,263.1i

Federal Unemployment

FICA

Medicare

CT Unemployment

MA Unemployment

MA Universal Health

VT Unemployment

NH Unemployment

Total To Line 23

** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments.

Shading denotes an input

ine
No.

FERC Form 1
Reference

PTF Transmission Plant Allocation Factor

VT TRANSCO

1	PTF Transmission Investment	626,275,495	NEPOOL Catalog
2	Total Transmission Investment	780,225,984	Page 207.58g
3	Percent Allocation (Line 1/Line 2)	80.2685%	

Transmission Wages and Salaries Allocation Factor

4	Direct Transmission Wages and Salaries	5,399,944	Page 354.21b
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 & 6a of 8
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	5,399,944	
7	Total Wages and Salaries	8,135,437	Page 354.28b
8	Administrative and General Wages and Salaries	2,735,493	Page 354.27b
9	Affiliated Company Wages and Salaries less A&G	0	Worksheet 6 & 6a of 8
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	5,399,944	
11	Percent Allocation (Line 6/Line 10)	100.0000%	

Plant Allocation Factor

12	Total Transmission Investment	780,225,984	Page 207.58g
13	plus Transmission-Related General Plant (Line 2 of Wkst. 3)	68,131,062	Page 207.99g
14	= Revised Numerator (Line 12 + Line 13)	848,357,046	
15	Total Plant in Service	854,498,133	Page 207.104g
16	Percent Allocation (Line 14 / Line 15)	99.2813%	

Affiliated Company Wages and Salaries

Shading denotes an input

Line	VT TRANSCO	
"Affiliated" Transmission Wages and Salaries		
#560 - 573		
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11 = 1 thru 10 Total Transmission		0

12 = Total "Affiliated" Wages 0

Less "Affiliated" Administrative and General Salaries

#920 - 935

13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
1 = 13 thru 20		0

2 = 12 less 2 Total "Affiliated" less A&G 0

Input Revenues associated with the PTF Supporting Facilities in columns (a) and e with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 2

Particip	PTF Supporting Facilities	FERC Form 1	TOTAL	
			Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	32.(g); [332.1(g) for HWP]		40,023
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			2,825
	115 kV Wyman 164-167 lines			6,133
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			242,206
	Comerford 115 kV Substation			50,860
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	32.1(g); [332(g) for CL&P]		572,712
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury	332(g)		
	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310	330.1(n)		61,221
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
Total =			0	975,979

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

NEPOOL Tariff Billing
NEPOOL Annual Transmission Revenue Requirements
per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3

Shading denotes an input

POST-96

Submitted on:	May 14, 2012
Revenue Requirements for (year):	Calendar Yr 2011 \$ 101,956,847
Customer:	VT TRANSCO LLC
Customer's NABs Number:	52
Name of Participant responsible for customer's billing:	VT TRANSCO LLC
DUNS number of Participant responsible for customer's billing:	78-0399163

	Pre-97 Revenue Requirements	Post-96 Revenue Requirements
Total of Attachment F - Sections A through I =	0 (a)	101,502,329 (f)
Total of Attachment F - Section J - Support Revenue	0 (b)	(g)
Total of Attachment F - Section K - Support Expense	0 (c)	(h)
Total of Attachment F - Section (L through O)	(d)	454,518 (i)
Sub Total - Sum (A through I) - J + K + (L through O)	0 (e)=(a)-(b)+(c)+(d)	101,956,847 (j)

Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:	101,956,847 (k) = (e) + (j)

Total of Attachment F - Section J - Pre-97 Support Revenue (from above)	0 (b)
Total of Attachment F - Section J - Post-96 Support Revenue (from above-)	0 (g)
Total of Attachment F - Section K - Post-96 Support Expense (from above)	0 (h)

Total Post-96 Revenue Requirements	101,956,847 (l)=(k)+(b)+(g)-(h)

VT TRANSCO
Annual Revenue Requirements of PTF Facilities
for costs in 2011

PTF Revenue Requirements

Worksheet 1 of 8

Shading denotes an input

		Attachment F		
		Reference	Total	Reference
Line N	I. INVESTMENT BASE	Section:		
1	Transmission Plant	(A)(1)(a)	565,827,989	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	49,409,327	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		615,237,316	
5	Accumulated Depreciation	(A)(1)(d)	91,186,237	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	41,946,951	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	0	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	0	Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		482,104,128	
10	Prepayments	(A)(1)(h)	1,219,654	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	5,598,102	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	1,387,327	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		490,309,211	
II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	63,862,678	Worksheet 2
	Investment Return and Income Taxes Post-2003 Increment		2,081,030	Worksheet adder
15	Depreciation Expense	(B)	14,082,160	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	0	Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)	0	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	9,632,183	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	745,661	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	(G)	5,935,605	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	5,163,012	Worksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	0	Worksheet 7
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	489,987	Gross Revenue Tax
27	Revenue for ST Trans. Service Under NEPOOL	(N)	(20,868)	Schedule 8 TOUT Revenues
28	Transmission Rents Received from Electric Proj	(O)	(14,600)	Rev Rent 4000-454122
29	Total Revenue Requirements (Line 14 thru 28)		101,956,847	

VT TRANSCO
Annual Revenue Requirements
for costs in 2011

Shading denotes an input

	CAPITALIZATION 12/31/11		CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF EQUITY CAPITAL PORTIOI
LONG-TERM DEBT	\$ 317,272,000	Page 112.24c	45.47%	5.52%	2.51%
PREFERRED STOCK	0		0.00%	0.00%	0.00%
COMMON EQUITY	380,424,246	Page 112.16c	54.54%	11.64%	6.35%
TOTAL INVESTMEN	\$ 697,696,246		100.01%	8.86%	6.35%

Cost of Capital Rate=

(a) Weighted Cost o = 0.0886

(b) Federal Income Tax =
$$\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Depreciation}}{\text{PTF Inv. Base}} \right) \times \text{Federal Income Tax Rate}}{\left(\frac{\text{R.O.E.}}{1} + \frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Depreciation}}{\text{PTF Inv. Base}} \right) \times \text{Federal Income Tax Rate}}$$

=
$$\frac{0.0635 + \left(\frac{0 + 0}{490,309,211} \right) \times 0.34}{\left(\frac{0.0635}{1} + \frac{0}{490,309,211} \right) \times 0.34}$$

= 0.0327121

(c) State Income Tax =
$$\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Depreciation}}{\text{PTF Inv. Base}} \right) \times \text{Federal Income Tax Rate}}{\left(\frac{\text{R.O.E.}}{1} + \frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Depreciation}}{\text{PTF Inv. Base}} \right) \times \text{Federal Income Tax Rate}} \times \text{State Income Tax Rate}$$

=
$$\frac{0.0635 + \left(\frac{0 + 0}{490,309,211} \right) \times 0.0327121}{\left(\frac{0.0635}{1} + \frac{0}{490,309,211} \right) \times 0.085} \times 0.085$$

= 0.0089377

(a)+(b)+(c) **Cost of** = 0.1302498

(PTF)

INVESTMENT BASE \$ 490,309,211 From Worksheet 1

x Cost of Capital Rate 0.1302498

= Investment Return and 63,862,678 To Worksheet 1

VT TRANSCO
Annual Revenue Requirements
for costs in 2011

Shading denotes an input

	CAPITALIZATION 12/31/11	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 317,272,000	45.47%		0.00%	
PREFERRED STOCK	0	0.00%		0.00%	0.00%
COMMON EQUITY	380,424,246	54.54%	1.00%	0.55%	0.55%
TOTAL INVESTMENT RETURN	\$ 697,696,246	100.01%		0.55%	0.55%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0055

$$\begin{aligned}
 \text{(b) Federal Income Tax} &= \left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Depre}}{\text{PTF Inv. Base}} \right)}{1} \right) \times \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}} \\
 &= \left(\frac{0.0055 + \frac{0 + 0}{228,498,757}}{1} \right) \times \frac{0.34}{0.34} \\
 &= 0.0028333
 \end{aligned}$$

$$\begin{aligned}
 \text{(c) State Income Tax} &= \left(\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Depre}}{\text{PTF Inv. Base}} \right)}{1} \right) + \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}} \times \text{State Income Tax Rate} \\
 &= \left(\frac{0.0055 + \frac{0 + 0}{228,498,757}}{1} \right) + \frac{0.0028333}{0.085} \times 0.085 \\
 &= 0.0007741
 \end{aligned}$$

(a)+(b)+(c) **Cost of Capital Rate** = 0.0091074

(PTF)

Post-2003 INVESTMENT BASE	
PTF Transmission Plant	289,188,624
less Accum Depreciation Reserve	39,096,023
less Accum Deferred Taxes	(21,593,844)
Post-2003 INVESTMENT BASE	228,498,757

INVESTMENT BASE \$ 228,498,757 From Worksheet Post-2003

x Cost of Capital Rate 0.0091074

= Investment Return and Income Taxes 2,081,030 To Worksheet 1

VT TRANSCO
Annual Revenue Requirements of post-2003 PTF Incremental Return
for costs in 2011

RNS Rate

Worksheet 1b of 8

		(1) Total	(2) Post-2003 ¹	
		Transmission	PTF	Total Transmission Reference
Line No.	I. INVESTMENT BASE			
1	Transmission Plant	780,225,984	289,188,624	Internal Plant Accounting
2	Accumulated Depreciation	105,480,405	39,096,023	Worksheet 3, line 5 column 1 + line 5A column 1
3	Accumulated Deferred Income Taxes	(58,259,823)	(21,593,844)	Worksheet 3, line 10 column 3
4	Other Regulatory Assets	0	-	Worksheet 3a, line 15 column 3
5	Net Investment (Line 1-2-3+4)	616,485,756	228,498,757	
II. INCREMENTAL RETURN				
6	Incremental Revenue Requirements		2,081,030	Worksheet 2a
7	PTF Transmission Plant Allocation Factor		37.0647%	

Notes: 1. line 2 column 2 = line 2 column 1 * line 7 column 2
line 3 column 2 = line 3 column 1 * line 7 column 2
line 4 column 2 = line 4 column 1 * line 7 column 2
line 7 column 2 = line 1 column 2 / line 1 column 1

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
<u>Transmission Plant</u>						
1	Transmission Plant	780,225,984	780,225,984		565,827,989	Line 1, Worksheet 1
2	General Plant	68,131,062	100.0000% (a) 68,131,062	72.5210%	49,409,327	Page 207.99g
3	Total (line 1+2)		848,357,046		615,237,316	
4	Transmission Plant Held for Future Use	0	0	72.5210%	0	Page 214.47d
<u>Transmission Accumulated Depreciation</u>						
5	Transmission Accum. Depreciation	105,480,405	105,480,405	72.5210%	76,495,445	Page 219.25b
6	General Plant Accum. Depreciation	20,257,294	100.0000% (a) 20,257,294	72.5210%	14,690,792	Page 219.27b
7	Total (line 5+6)		125,737,699		91,186,237	
<u>Transmission Accumulated Deferred Taxes</u>						
8	Accumulated Deferred Taxes (281-28)	(58,259,823)	99.2813% (c) (57,841,110)	72.5210%	(41,946,951)	Page 113.63d
9	Accumulated Deferred Taxes (190)	0	99.2813% (c) 0	72.5210%	0	Page 111.68d
10	Total (line 8+9)		(57,841,110)		(41,946,951)	
11	Transmission loss on Reacquired Debt	0	99.2813% (c) 0	72.5210%	0	Page 111.81d
<u>Other Regulatory Assets</u>						
12	FAS 106	0	100.0000% (a) 0	72.5210%	0	Page 232.30e
13	FAS 109	0	99.2813% (c) 0	72.5210%	0	Page 232.21&23e
14	Other Regulatory Liabilities (254.DK)	0	99.2813% (c) 0	72.5210%	0	Page 278.1e
15	Total (line 12+13+14)	0	0		0	
16	Transmission Prepayments	1,681,794	100.0000% (a) 1,681,794	72.5210%	1,219,654	Page 111.57c
17	Transmission Materials and Supplies	7,719,284	7,719,284	72.5210%	5,598,102	Page 227.8c
<u>Cash Working Capital</u>						
19	Operation & Maintenance Expense				5,935,605	Worksheet 1, Line 1
20	Administrative & General Expense				5,163,012	Worksheet 1, Line 1
21	Transmission Support Expense				0	Worksheet 1, Line 1
22	Subtotal (line 19+20+21)				11,098,617	
23					0.125	x 45 / 360
24	Total (line 22 * line 23)				1,387,327	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

VT TRANSCO

PTF Revenue Requirements
Worksheet 4a of 8

Sheet: Worksheet 4

(2)

(4)

Shading denotes an input

Line No.	(1) Total	Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
<u>Depreciation Expense</u>						
1	15,707,503		15,707,503	72.5210%	11,391,238	Page 336.7b
2	3,710,542	100.0000% (a)	3,710,542	72.5210%	2,690,922	Page 336.9b
3			19,418,045		14,082,160	
4	0	99.2813% (c)	0	72.5210%	0	Page 117.64c
5		99.2813% (c)	0	72.5210%	0	Page 266.8f
<u>Property Taxes *</u>						
6	13,281,923	99.2813% (c)	13,281,923	72.5210%	9,632,183	Page 262-263 FN.1-2
7			0	72.5210%	0	Page 262-263 FN.1-2
8			13,281,923		9,632,183	
<u>Transmission Operation and Maintenance</u>						
9	11,811,480		11,811,480	72.5210%	8,565,803	Page 321.112b
10	473,135		473,135	72.5210%	343,122	Page 321.96b
11	3,102,815		3,102,815	72.5210%	2,250,192	Page 321.84 - 88b
12	50,860		50,860	72.5210%	36,884	Page 321.93b & .98b
13	8,184,670		8,184,670		5,935,605	
<u>Transmission Administrative and General</u>						
14	7,128,490					Page 323.197b
15	675,526					Page 323.185b
16	299,593					Page 323.189b
17	298,697					Page 323.191b
18	5,854,674	100.0000% (a)	5,854,674	72.5210%	4,245,868	
19	675,526	99.2813% (c)	670,671	72.5210%	486,377	
20	299,593	99.2813% (c)	297,440	72.5210%	215,706	
21	298,697	99.2813% (c)	296,550	72.5210%	215,061	
22	7,128,490		7,119,335		5,163,012	
23	1,028,200	100.0000% (a)	1,028,200	72.5210%	745,661	Footnote (d)

* Property Taxes functionalized per FERC Form 1; therefore, no need to use Plant Allocation Factor

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

(d) Payroll taxes FERC Form 1, page 263.i ,263.1i

Federal Unemployment	9,240
FICA	949,386
Medicare	0
CT Unemployment	0
MA Unemployment	0
MA Universal Health	0
VT Unemployment	69,574
NH Unemployment	0
Total	1,028,200 To Line 23

** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments.

Shading denotes an input

Line
No.FERC Form 1
Reference**PTF Transmission Plant Allocation Factor** **VT TRANSCO**

1	PTF Transmission Investment	565,827,989	NEPOOL Catalog
2	Total Transmission Investment	780,225,984	Page 207.58g
3	Percent Allocation (Line 1/Line 2)	72.5210%	

Transmission Wages and Salaries Allocation Factor

4	Direct Transmission Wages and Salaries	5,399,944	Page 354.21b
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 & 6a of 8
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	5,399,944	
7	Total Wages and Salaries	8,135,437	Page 354.28b
8	Administrative and General Wages and Salaries	2,735,493	Page 354.27b
9	Affiliated Company Wages and Salaries less Administrative and General	0	Worksheet 6 & 6a of 8
10	Total Wages and Salaries net of A&G (Line 7 - Line 9)	5,399,944	
11	Percent Allocation (Line 6/Line 10)	100.0000%	

Plant Allocation Factor

12	Total Transmission Investment	780,225,984	Page 207.58g
13	plus Transmission-Related General Plant (Line 13)	68,131,062	Page 207.99g
14	= Revised Numerator (Line 12 + Line 13)	848,357,046	
15	Total Plant in Service	854,498,133	Page 207.104g
16	Percent Allocation (Line 14 / Line 15)	99.2813%	

Affiliated Company Wages and Salaries

Shading denotes an input

Line		VT TRANSCO
"Affiliated" Transmission Wages and Salaries		
#560 - 573		
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11 = 1 thru 10 Total Transmission		0

12 = Total "Affiliated" Wages 0

Less "Affiliated" Administrative and General Salaries
#920 - 935

13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
1 = 13 thru 20		0

2 = 12 less 2 Total "Affiliated" less A&G 0

Input Revenues associated with the PTF Supporting Facilities in columns (a) and e with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 2

Particip	PTF Supporting Facilities	FERC Form 1	TOTAL	
			Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	32.(g); [332.1(g) for HWP]		
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			
	Comerford 115 kV Substation			
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	32.1(g); [332(g) for CL&P]		
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury	332(g)		
	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310	330.1(n)		
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
Total =			0	0

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

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VT TRANSCO
Forecasted Transmission Revenue Requirements of PTF Facilities

POST-1996

Shading denotes an input

		Attachment F		
I. <u>FORECASTED TRANSMISSION REVENUE REQUIREMENT</u>		Reference	VELCO	Reference
		Section:		
Line No.	Period			
1	2012	Appendix C	\$40,000,000	
2		Appendix C	17.57%	
3			<u>\$7,028,376</u>	
II. <u>CARRYING CHARGE FACTOR</u>				
4		(A)	\$63,862,678	Summary, line 14
5		(B)	\$14,082,160	Summary, line 15
6		(C)	\$0	Summary, line 16
7		(D)	\$0	Summary, line 17
8		(E)	\$9,632,183	Summary, line 18
9		(F)	\$745,661	Summary, line 19
10		(G)	\$5,935,605	Summary, line 20
11		(H)	<u>\$5,163,012</u>	Summary, line 21
12			\$99,421,299	
13		(A)(1)(a)	<u>\$565,827,989</u>	Summary, line 1
14			<u>17.57%</u>	

VERMONT TRANSCO LLC
Forecasted Transmission Revenue Requirements of PTF Facilities
Calendar Year 2012

	<u>Estimated Additional PTF In Service for 2012</u>
Southern Loop	5,000,000
Georgia Substation	14,000,000
Reactor Additions	16,000,000
Jay Substation	<u>5,000,000</u>
Total	<u><u>40,000,000</u></u>

NEPOOL Tariff Billing
NEPOOL Annual Transmission Revenue Requirements
per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3

Shading denotes an input

PRE-97

Submitted on:	<u>May 14, 2012</u>
Revenue Requirements for (year):	<u>Calendar Yr 2011 \$ 11,661,612</u>
Customer:	<u>VT TRANSCO LLC</u>
Customer's NABs Number:	<u>52</u>
Name of Participant responsible for customer's billing:	<u>VT TRANSCO LLC</u>
DUNs number of Participant responsible for customer's billing:	<u>78-0399163</u>

	<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>
Total of Attachment F - Sections A through I =	<u>10,637,077 (a)</u>	<u> (f)</u>
Total of Attachment F - Section J - Support Revenue	<u>0 (b)</u>	<u> (g)</u>
Total of Attachment F - Section K - Support Expense	<u>975,979 (c)</u>	<u> (h)</u>
Total of Attachment F - Section (L through O)	<u>48,556 (d)</u>	<u> (i)</u>
Sub Total - Sum (A through I) - J + K + (L through O)	<u>11,661,612 (e)=(a)-(b)+(c)+(d)</u>	<u>- (j)</u>
Pre-97 Revenue Requirements (per Attachment C to Attachment F Implementation Rule)		<u>11,661,612 (k) = (e) + (j)</u>
Total of Attachment F - Section J - Pre-97 Support Revenue (from above)		<u>0 (b)</u>
Total of Attachment F - Section J - Post-96 Support Revenue (from above-)		<u>0 (g)</u>
Total of Attachment F - Section K - Post-96 Support Expense (from above)		<u>0 (h)</u>
Total Pre-97 Revenue Requirements		<u><u>11,661,612 (l)=(k)+(b)+(g)-(h)</u></u>

VT TRANSCO
Annual Revenue Requirements of PTF Facilities
for costs in 2011

PTF Revenue Requirements
Worksheet 1 of 8

Shading denotes an input

Line No.		Attachment F Reference	Total	Reference
	I. INVESTMENT BASE	Section:		
1	Transmission Plant	(A)(1)(a)	60,447,507	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	5,278,386	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		65,725,893	
5	Accumulated Depreciation	(A)(1)(d)	9,741,403	Worksheet 3, line 7 column 5
6	Accumulated Deferred Inc	(A)(1)(e)	4,481,182	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	0	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	0	Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		51,503,308	
10	Prepayments	(A)(1)(h)	130,295	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	598,044	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	270,205	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		52,501,852	
	II. REVENUE REQUIREMENTS			
14	Investment Return and Inc (A)		6,838,356	Worksheet 2
15	Depreciation Expense (B)		1,504,394	Worksheet 4, line 3 column 5
16	Amortization of Loss on R(C)		0	Worksheet 4, line 4 column 5
17	Investment Tax Credit (D)		0	Worksheet 4, line 5 column 5
18	Property Tax Expense (E)		1,029,004	Worksheet 4, line 8 column 5
19	Payroll Tax Expense (F)		79,659	Worksheet 4, line 23 column 5
20	Operation & Maintenance (G)		634,100	Worksheet 4, line 13 column 5
21	Administrative & General I (H)		551,564	Worksheet 4, line 16 column 5
22	Transmission Related Inte (I)		0	Worksheet 7
23	Transmission Support Rev (J)		0	Worksheet 7
24	Transmission Support Exp (K)		975,979	Worksheet 7
25	Transmission Related Exp (L)		0	Worksheet 7
26	Transmission Related Tax (M)		52,345	Gross Revenue Tax FF 1 Page 263
27	Revenue for ST Trans. Se (N)		(2,229)	Schedule 8 TOUT Revenues
28	Transmission Rents Recei (O)		(1,560)	Rev Rent 4000-454122
29	Total Revenue Requirements (Line 14 thru 28)		11,661,612	

Shading denotes an input

	CAPITALIZATION 12/31/11		CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 317,272,000	Page 112.24c	45.47%	5.52%	2.51%	
PREFERRED STOCK	0		0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	380,424,246	Page 112.16c	54.54%	11.64%	6.35%	6.35%
TOTAL INVESTMENT R	\$ 697,696,246		100.01%		8.86%	6.35%

Cost of Capital Rate=

(a) Weighted Cost of Ca = 0.0886

$$\begin{aligned}
 \text{(b) Federal Income Tax} &= \frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec.}}{\text{PTF Inv. Base}} \right) \times \text{Federal Income Tax Rate}}{1 + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec.}}{\text{PTF Inv. Base}} \right) \times \text{Federal Income Tax Rate}} \\
 &= \frac{0.0635 + \left(\frac{0 + 0}{52,501,852} \right) \times 0.34}{1 + \left(\frac{0 + 0}{52,501,852} \right) \times 0.34} \\
 &= 0.0327121
 \end{aligned}$$

$$\begin{aligned}
 \text{(c) State Income Tax} &= \frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec.}}{\text{PTF Inv. Base}} \right) \times \text{Federal Income Tax Rate}}{1 + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec.}}{\text{PTF Inv. Base}} \right) \times \text{Federal Income Tax Rate}} \times \text{State Income Tax Rate} \\
 &= \frac{0.0635 + \left(\frac{0 + 0}{52,501,852} \right) \times 0.34}{1 + \left(\frac{0 + 0}{52,501,852} \right) \times 0.34} \times 0.085 \\
 &= 0.0089377
 \end{aligned}$$

(a)+(b)+(c) Cost of Capit = 0.1302498

	(PTF)	
INVESTMENT BASE	\$ 52,501,852	From Worksheet 1
x Cost of Capital Rate	0.1302498	
= Investment Return and Incom	6,838,356	To Worksheet 1

Sheet: Worksheet 3

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
<u>Transmission Plant</u>						
1	780,225,984		780,225,984		60,447,507	Line 1, Worksheet 5
2	68,131,062	100.0000% (a)	68,131,062	7.7474%	5,278,386	Page 207.99g
3			<u>848,357,046</u>		<u>65,725,893</u>	
4	<u>0</u>		0	7.7474%	<u>0</u>	Page 214.47d
<u>Transmission Accumulated Depreciation</u>						
5	105,480,405		105,480,405	7.7474%	8,171,989	Page 219.25b
6	20,257,294	100.0000% (a)	20,257,294	7.7474%	1,569,414	Page 219.28b
7			<u>125,737,699</u>		<u>9,741,403</u>	
<u>Transmission Accumulated Deferred Taxes</u>						
8	(58,259,823)	99.2813% (c)	(57,841,110)	7.7474%	(4,481,182)	Page 113.63c
9	0	99.2813% (c)	0	7.7474%	0	Page 111.82c
10			<u>(57,841,110)</u>		<u>(4,481,182)</u>	
11	<u>0</u>	99.2813% (c)	0	7.7474%	<u>0</u>	Page 111.81d
<u>Other Regulatory Assets</u>						
12	0	100.0000% (a)	0	7.7474%	0	Page 232.30e
13	0	99.2813% (c)	0	7.7474%	0	Page 232.21&23e
14	0	99.2813% (c)	0	7.7474%	0	Page 278.1e
15	<u>0</u>		<u>0</u>		<u>0</u>	
16	1,681,794	100.0000% (a)	1,681,794	7.7474%	<u>130,295</u>	Page 111.57c
17	7,719,284		7,719,284	7.7474%	<u>598,044</u>	Page 227.8c
<u>Cash Working Capital</u>						
19					634,100	Worksheet 1, Line 20
20					551,564	Worksheet 1, Line 21
21					975,979	Worksheet 1, Line 24
22					<u>2,161,643</u>	
23					0.125	x 45 / 360
24					<u>270,205</u>	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

		(2)		(4)		
Shading denotes an input						
Line No.	(1) Total	Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
<u>Depreciation Expense</u>						
1	Transmission Depreciation		15,707,503	7.7474%	1,216,923	Page 336.7b
2	General Depreciation	100.0000% (a)	3,710,542	7.7474%	287,471	Page 336.10b
3	Total (line 1+2)		19,418,045		1,504,394	
4	Amortization of Loss on Reacquired	99.2813% (c)	0	7.7474%	0	Page 117.64c
5	Amortization of Investment Tax Credits	99.2813% (c)	0	7.7474%	0	Page 266.8f
<u>Property Taxes *</u>						
6	Transmission Property Taxes	99.2813% (c)	13,281,923	7.7474%	1,029,004	Page 262-263 FN.1-2
7	General Property Taxes		0	7.7474%	0	Page 262-263 FN.1-2
8	Total (line 6+7)		13,281,923		1,029,004	
<u>Transmission Operation and Maintenance</u>						
9	Operation and Maintenance		11,811,480	7.7474%	915,083	Page 321.112b
10	Transmission of Electricity by Others		473,135	7.7474%	36,656	Page 321.96b
11	Load Dispatching - #561.1-561.4		3,102,815	7.7474%	240,387	Page 321.84 - 88b
12	**Station Expenses & Rents - #562 /		50,860	7.7474%	3,940	Page 321.93b & .98b
13	O&M less lines 10, 11 & 12		8,184,670		634,100	
<u>Transmission Administrative and General</u>						
14	Administrative and General		7,128,490			Page 323.197b
15	less Property Insurance (#924)		675,526			Page 323.185b
16	less Regulatory Commission Expense		299,593			Page 323.189b
17	less General Advertising Expense		298,697			Page 323.191b
18	Subtotal [line 14 minus (15 thru 17)]	100.0000% (a)	5,854,674	7.7474%	453,585	
19	PLUS Property Insurance alloc. us	99.2813% (c)	670,671	7.7474%	51,960	
20	PLUS Regulatory Comm. Exp. (F)	99.2813% (c)	297,440	7.7474%	23,044	
21	PLUS Trans. Related General Adv	99.2813% (c)	296,550	7.7474%	22,975	
22	Total A&G [line 18 plus (19 thru 21)]		7,119,335		551,564	
23	Payroll Tax Expense	100.0000% (a)	1,028,200	7.7474%	79,659	Footnote (d)

* Property Taxes functionalized per FERC Form 1; therefore, no need to use Plant Allocation Factor

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

(d) Payroll taxes FERC Form 1, page 263.i ,263.1i

Federal Unemployment	9,240	
FICA	949,386	
Medicare	0	
CT Unemployment	0	
MA Unemployment	0	
MA Universal Health	0	
VT Unemployment	69,574	
NH Unemployment	0	
Total	1,028,200	To Line 23

** Subtract Accounts #567 from O&M Expense to the extent that they include PTF Support Payments.

VT TRANSCO

Sheet: Worksheet 5

PTF Revenue Requirements
Worksheet 5 of 8

Shading denotes an input

Line
No.FERC Form 1
Reference**PTF Transmission Plant Allocation Factor** VT TRANSCO

1	PTF Transmission Investment	60,447,507	NEPOOL Catalog
2	Total Transmission Investment	780,225,984	Page 207.58g
3	Percent Allocation (Line 1/Line 2)	7.7474%	

Transmission Wages and Salaries Allocation Factor

4	Direct Transmission Wages and Salaries	5,399,944	Page 354.21b
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 & 6a of 8
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	5,399,944	
7	Total Wages and Salaries	8,135,437	Page 354.28b
8	Administrative and General Wages and Salaries	2,735,493	Page 354.27b
9	Affiliated Company Wages and Salaries less Administrative and General Wages and Salaries	0	Worksheet 6 & 6a of 8
10	Total Wages and Salaries net of A&G (Line 7 - Line 9)	5,399,944	
11	Percent Allocation (Line 6/Line 10)	100.0000%	

Plant Allocation Factor

12	Total Transmission Investment	780,225,984	Page 207.58g
13	plus Transmission-Related General Plant (Line 13)	68,131,062	Page 207.99g
14	= Revised Numerator (Line 12 + Line 13)	848,357,046	
15	Total Plant in Service	854,498,133	Page 207.104g
16	Percent Allocation (Line 14 / Line 15)	99.2813%	

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Particip	PTF Supporting Facilities	FERC Form 1	TOTAL	
			Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	2.(g); [332.1(g) for HWP]		40,023
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			2,825
	115 kV Wyman 164-167 lines			6,133
	115 kV Maine Yankee transmis	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			242,206
	Comerford 115 kV Substation			50,860
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	2.1(g); [332(g) for CL&P]		572,712
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewks	332(g)		
	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester	330.1(n)		61,221
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
Total =			0	975,979

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

**VERMONT TRANSCO LLC
ROLLFORWARD PTF INVESTMENT**

		Investment as of				Investment as of
		12/31/10	Additions	Retirements	Adjustments	12/31/11
SUBSTATIONS						
20S	Highgate Converter	35,313.29				35,313.29
28S	Charlotte Substation	759,364.12	2,476.85		144,494.91	906,335.88
30S	West Rutland	15,747,615.98	2,259,613.31	640,348.85	116,671.54	17,483,551.98
40S	Vermont Yankee Substation	11,657,642.17	2,334,572.08	642,137.42		13,350,076.83
44S	Vergennes Substation	4,448,103.57	2,513.37		6,206.04	4,456,822.98
45S	Ferrisburg	1,122,669.41	2,331.50		(188,393.05)	936,607.86
52S	Granite	84,993,636.92	143,260.07		103,325.03	85,240,222.02
53S	Shelburne Substation	810,670.53	2,332.13		(53,813.47)	759,189.19
54S	Coolidge 115/345 Kv	23,747,264.51	668,464.14	73,900.28	198,906.72	24,540,735.09
61S	St Albans	44,737.83	9,294.93			54,032.76
62S	Essex	22,433,150.03	43,882.49			22,477,032.52
63S	Barre	214,710.82	26,852.11			241,562.93
64S	East Ave Substation	4,196,790.63	43,298.36			4,240,088.99
65S	Middlesex Substation	1,508,152.25			(697,195.23)	810,957.02
66S	St Johnsbury	1,391,084.76				1,391,084.76
68S	Irasburg	883,463.71				883,463.71
69S	Queen City Substation	4,836,647.54	13,046.14			4,849,693.68
70S	Ascutney	588,062.83				588,062.83
71S	North Rutland	1,101,502.43	78,990.52			1,180,492.95
72S	Middlebury	932,968.10	274,809.27	12,977.24		1,194,800.13
73S	Bennington	2,803,682.68	78,490.52			2,882,173.20
74S	New Haven	30,344,638.23			(1,253,742.48)	29,090,895.75
75S	Chelsea	156,532.26	40,278.03			196,810.29
76S	Blissville	10,686,118.96				10,686,118.96
77S	Hartford	3,063,098.88				3,063,098.88
79S	Newfane	11,004,373.22	227,960.65			11,232,333.87
80S	Georgia	1,549,193.94				1,549,193.94
81S	St Albans	1,125,855.02				1,125,855.02
82S	Sandbar	8,758,622.14	10,784.34	20,987.53		8,748,418.95
83S	Williston	5,391,054.59				5,391,054.59
85S	Vernon Substation	41,847,857.86	1,029,242.26	5,186.70		42,871,913.42
86S	Lyndonville Substation	6,403,591.20	61,049.21			6,464,640.41
87S	Line Kiln Substation	7,481,466.90	223,763.70			7,705,230.60
89S	Cold River	1,150,056.70				1,150,056.70
91S	Berlin	1,171,293.01	92,950.61			1,264,243.62
93S	Highgate	8,338,657.59	462,322.18			8,800,979.77
95S	South Hero	384,864.41	56,802.35			441,666.76
98S	GMP Taft Corner	5,108,281.74				5,108,281.74
101S	Duxbury Switching Station	574,953.84				574,953.84
		328,797,744.59	8,189,381.12	1,395,538.02	(1,623,539.99)	333,968,047.70
LINES						
	Bennington - Searsburg	1,456,023.02				1,459,049.00
04L	Bennington-Mass. State Ln	999,099.07				999,099.07
06L	Bennington-N.Y. State Ln	347,725.42				347,725.42
07L	Rutland-West Rutland	360,709.51	15,617.07	892.22		375,434.36
14L	Ascutney-NEES	90,789.76				90,789.76
17L	Ascutney-PSNH	69,342.11				69,342.11
18L	Vernon-Keene Tie	205,551.70	4,807.19	6,932.35		203,426.54
19L	Sandbar-Georgia	786,816.23				786,816.23
20L	Lk Champlain Cable Cross	1,008,452.99				1,008,452.99
21L	Georgia-Highgate	2,377,018.31	27,237.10	1,875.30		2,402,380.11
22L	Lake Champlain-Essex	4,682,231.82				4,682,231.82
23L	Essex-Middlebury	4,241,379.28	27,237.12	969.96		4,267,646.44
24L	Essex-Barre	1,623,005.27	76,920.04	1,685.41		1,698,239.90
25L	Essex-Burlington	17,056,364.00	28,844.51			17,085,208.51
26L	Barre-Wilder	3,320,866.69				3,320,866.69
27L	Essex-Georgia	1,393,426.71	144,076.30	12,605.66		1,524,897.35
28L	Barre-Comerford	3,611,286.42				3,611,286.42
29L	St. Johnsbury-Littleton	831,735.75				831,735.75
30L	West Rutland-Middlebury	4,708,892.53				4,708,892.53
31L	Rutland-Ascutney	1,917,069.96	1,555,405.50	20,907.04		3,451,568.42
33L	Queen City Tap	2,003,227.09				2,003,227.09
35L	WEST RUTL MIDDLEBURY 345K	49,580,309.60				49,580,309.60
37L	Vernon-Scobie Tie	619,586.67	5,447.25	173,204.36		451,829.56
38L	Vernon-Northfield Tie	564,996.97	5,389.55	156,909.66		413,476.86
39L	St. Johnsbury-Irasburg	3,473,834.41		18,277.03		3,455,557.38
40L	Vernon-Coolidge	9,435,872.73	1,304,972.97	92,948.12		10,647,897.58
41L	Coolidge-West Rutland	8,464,011.58				8,464,011.58
42L	Richford-New Highgate 120	1,555,896.00	696,444.45		491,898.43	2,744,238.88
44L	NEWPORT-RICHFORD(120kV)	2,316,608.50			833,842.41	3,150,450.91
47L	Irasb to Moshers Tap 115k	4,553,701.20				4,553,701.20
48L	New Haven to Queen City	61,213,704.69	170,970.86	761,130.59		60,623,544.96
49L	Duxbury - Stowe	1,633,331.45	7,501.41			1,640,832.86
51L	Newfane - Vernon	35,115,513.52	1,047,445.45			36,162,958.97
52L	Newfane - Coolidge	52,881,036.79	1,539,484.44			54,420,521.23
53L	Vernon - VY	110,693.08	3,316.87			114,009.95
54L	Vernon - Vernon	1,421,294.98	40,035.98			1,461,330.96
L34	West Rutland - Whitehall	953,507.31	0.00			953,507.31
		286,984,913.12	6,701,154.06	1,248,337.70	1,325,740.84	293,766,496.30
TOTAL PTF Facilities		615,782,657.71	14,890,535.18	2,643,875.72	(297,799.15)	627,734,544.00

HIGHGATE JOINT OWNERS

Revenue
Requirements
Year End 2011

City of Burlington Electric Department	280,924.00
Central Vermont Public Service Corporation	3,218,558.00
Green Mountain Power Corporation	1,389,974.00
Vermont Public Power Supply Authority	257,639.00
Johnson	49,153.00
	5,196,248.00

NEPOOL Tariff Billing
NEPOOL Annual Transmission Revenue Requirements
per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3

Shading denotes an input

TOTAL

Submitted on: _____ RTO ROE filing

Revenue Requirements for (year): **Calendar Yr 2011** \$ **3,218,558**

Customer: _____

Customer's NABs Number: _____

Name of Participant responsible for customer's billing: _____

DUNs number of Participant responsible for customer's billing: _____

	<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>
Total of Attachment F - Sections A through I =	<u>3,218,559</u> (a)	<u> </u> (f)
Total of Attachment F - Section J - Support Revenue	<u>0</u> (b)	<u> </u> (g)
Total of Attachment F - Section K - Support Expense	<u>0</u> (c)	<u> </u> (h)
Total of Attachment F - Section (L through O)	<u>(1)</u> (d)	<u> </u> (i)
Sub Total - Sum (A through I) - J + K + (L through O)	<u>3,218,558</u> (e)=(a)-(b)+(c)+(d)	<u>-</u> (j)
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:		<u>3,218,558</u> (k) = (e) + (j)
Total of Attachment F - Section J - Pre-97 Support Revenue (from above)		<u>0</u> (b)
Total of Attachment F - Section J - Post-96 Support Revenue (from above-)		<u>0</u> (g)
Total of Attachment F - Section K - Post-96 Support Expense (from above)		<u>0</u> (h)
Voting Share Total for Participant's R Value: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)		<u><u>3,218,558</u></u> (l)=(k)+(b)+(g)-(h)

Annual Revenue Requirements of PTF Facilities
for costs in 2011

PTF Revenue Requirements

Worksheet 1 of 8

Shading denotes an input

		Attachment F		
Line N		Reference	Total	Reference
	<u>I. INVESTMENT BASE</u>	Section:		
1	Transmission Plant	(A)(1)(a)	14,512,363	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	409,210	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	958	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		14,922,531	
5	Accumulated Depreciation	(A)(1)(d)	5,914,935	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	1,965,584	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	0	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	13,298	Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		7,055,310	
10	Prepayments	(A)(1)(h)	140,217	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	215,756	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	183,132	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		7,594,415	
	<u>II. REVENUE REQUIREMENTS</u>			
14	Investment Return and Income Taxes	(A)	968,616	Worksheet 2
15	Depreciation Expense	(B)	365,298	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	0	Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)	(5,708)	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	397,533	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	27,764	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	(G)	1,045,254	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	419,802	Worksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	0	Worksheet 7
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)		
27	Revenue for ST Trans. Service Under NEPOOL Tar	(N)		
28	Transmission Rents Received from Electric Property	(O)		
29	Total Revenue Requirements (Line 14 thru 28)		3,218,559	

**Annual Revenue Requirements
for costs in 2011**

Shading denotes an input

	CAPITALIZATION 12/31/2011	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 240,578,319	46.55%	5.70%	2.65%	
PREFERRED STOCK	8,053,800	1.56%	4.90%	0.00%	0.00%
COMMON EQUITY	268,152,973	51.90%	11.64%	6.04%	6.04%
TOTAL INVESTMENT	\$ 516,785,092	100.01%		8.69%	6.04%

Cost of Capital Rate=

(a) Weighted Cost of = 0.0869

(b) Federal Income Tax =
$$\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec} }{\text{PTF Inv. Base}} \right) \times \text{Federal Income Tax Rate}}{\left(1 - \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}} \right)}$$

=
$$\frac{0.0604 + \left(\frac{(5,708) + 0}{7,594,415} \right) \times 0.35}{\left(1 - 0.35 \right)}$$
 I know GMP and CVPS i

= 0.0321184

(c) State Income Tax =
$$\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec} }{\text{PTF Inv. Base}} \right) + \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}}}{\left(1 - \frac{\text{State Income Tax Rate}}{\text{State Income Tax Rate}} \right)}$$

=
$$\frac{0.0604 + \left(\frac{(5,708) + 0}{7,594,415} \right) + \frac{0.0321184}{0.085}}{\left(1 - 0.085 \right)}$$

= 0.0085248

(a)+(b)+(c) **Cost of C** = 0.1275432

(PTF)

INVESTMENT BASE \$ 7,594,415 From Worksheet 1

x Cost of Capital Rate 0.1275432

= Investment Return and Ir 968,616 To Worksheet 1

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (
<u>Transmission Plant</u>						
1	79,812,164		79,812,164		14,512,363	Line 1, Workshe
2	40,752,123	5.5224% (a)	2,250,498	18.1831%	409,210	Page 207.99g
3			82,062,662		14,921,573	
4	42,819	12.3088%	5,271	18.1831%	958	Page 214.47d
<u>Transmission Accumulated Depreciation</u>						
5	31,410,082		31,410,082	18.1831%	5,711,327	Page 219.25b
6	20,276,798	5.5224% (a)	1,119,767	18.1831%	203,608	Page 219.28b
7			32,529,849		5,914,935	
<u>Transmission Accumulated Deferred Taxes</u>						
8	124,808,708	12.3088% (c)	15,362,454	18.1831%	2,793,370	Page 113.(62-64
9	(36,985,753)	12.3088% (c)	(4,552,502)	18.1831%	(827,786)	Page 111.82c
10			10,809,952		1,965,584	
11	0	12.3088% (c)	0	18.1831%	0	Page 111.81d
<u>Other Regulatory Assets</u>						
12	0	5.5224% (a)	0	18.1831%	0	Page 232.30e
13	4,722,061	12.3088% (c)	581,229	18.1831%	105,685	Page 232.11f
14	(4,127,877)	12.3088% (c)	(508,092)	18.1831%	(92,387)	Page 278.1e
15	594,184		73,137		13,298	
16	13,963,831	5.5224% (a)	771,139	18.1831%	140,217	Page 111.57c
17	1,186,573		1,186,573	18.1831%	215,756	Page 227.8c
18	<u>Cash Working Capital</u>					
19	Operation & Maintenance Expense					Worksheet 1, Lir
20	Administrative & General Expense					Worksheet 1, Lir
21	Transmission Support Expense					Worksheet 1, Lir
22	Subtotal (line 19+20+21)					
23						x 45 / 360
24	Total (line 22 * line 23)					

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

Shading denotes an input

Worksheet 4

Worksheet 4a of 4

		(2)		(4)			
	Shading denotes an input						
		for costs in 2005					
Line No.		(1) Total	Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
	<u>Depreciation Expense</u>						
1	Transmission Depreciation	1,821,112		1,821,112	18.1831%	331,135	Page 336.7b
2	General Depreciation	3,402,228	5.5224% (a)	187,885	18.1831%	34,163	Page 336.10b
3	Total (line 1+2)			2,008,997		365,298	
4	<u>Amortization of Loss on Reacquired Debt</u>	0	(c)		18.1831%	0	Page 117.64c
5	<u>Amortization of Investment Tax Credits</u>	255,022	12.3088% (c)	31,390	18.1831%	5,708	Page 266.8f
	<u>Property Taxes *</u>						
6	Transmission Property Taxes	12,260,936	12.3088% (c)	1,509,174	18.1831%	274,415	Page 262-263 FN.1-2
7	General Property Taxes	12,260,936	5.5224%	677,099	18.1831%	123,118	Page 262-263 FN.1-2
8	Total (line 6+7)			2,186,273		397,533	
	<u>Transmission Operation and Maintenance</u>						
9	Operation and Maintenance	40,207,693		40,207,693	18.1831%	7,311,005	Page 321.112b
10	Transmission of Electricity by Others - #565	34,393,687		34,393,687	18.1831%	6,253,839	Page 321.96b
11	Load Dispatching - #561	65,511		65,511	18.1831%	11,912	Page 321.84b
12	**Station Expenses & Rents - #562 / #567	0		0	18.1831%	0	Page 321.85b & .90b
13	O&M less lines 10, 11 & 12	5,748,495		5,748,495		1,045,254	
	<u>Transmission Administrative and General</u>						
14	Administrative and General	38,873,721					Page 323.197b
15	less Property Insurance alloc. using Plant Allocator (#924)	843,344					Page 323.185b
16	less Regulatory Commission Expenses (#928)	1,543,557					Page 323.189b
17	less General Advertising Expense (#930.1)	0					Page 323.191b
18	Subtotal [line 14 minus (15 thru 17)]	36,486,820	5.5224% (a)	2,014,950	18.1831%	366,380	
19	PLUS Property Insurance alloc. using Plant Allocator	843,344	12.3088% (c)	103,806	18.1831%	18,875	
20	PLUS Regulatory Comm. Exp. (FERC Assessments)	1,543,557	12.3088% (c)	189,993	18.1831%	34,547	
21	PLUS Trans. Related General Advertising Expense	0	12.3088% (c)	0	18.1831%	0	
22	Total A&G [line 18 plus (19 thru 21)]	38,873,721		2,308,749		419,802	
23	<u>Payroll Tax Expense</u>	2,764,903	5.5224% (a)	152,689	18.1831%	27,764	Footnote (d)

* Property Taxes functionalized per FERC Form 1; therefore, no need to use Plant Allocation Factor

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

(d) Payroll taxes FERC Form 1, page 263.i, 263.1i

Federal Unemployment	24,571
FICA	2,591,007
Medicare	0
CT Unemployment	
MA Unemployment	
MA Universal Health	
VT Unemployment	149,325
NH Unemployment	0
Total	2,764,903 To Line 23

** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments.

Shading denotes an input

Line
No.FERC Form 1
Reference**PTF Transmission Plant Allocation Factor**

1	PTF Transmission Investment	14,512,363	NEPOOL Catalog
2	Total Transmission Investment	79,812,164	Page 207.58g
		0	
3	Percent Allocation (Line 1/Line 2)	18.1831%	

Transmission Wages and Salaries Allocation Factor

4	Direct Transmission Wages and Salaries	1,379,864	Page 354.21b
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 & 6a of 8
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	1,379,864	
7	Total Wages and Salaries	37,440,863	Page 354.28b
8	Administrative and General Wages and Salaries	12,454,216	Page 354.27b
9	Affiliated Company Wages and Salaries less A&G	0	Worksheet 6 & 6a of 8
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	24,986,647	
11	Percent Allocation (Line 6/Line 10)	5.5224%	

Plant Allocation Factor

12	Total Transmission Investment	79,812,164	Page 207.58g
13	plus Transmission-Related General Plant (Line 2 of Wkst. 3)	2,250,498	Page 207.99g
14	= Revised Numerator (Line 12 + Line 13)	82,062,662	
15	Total Plant in Service	666,698,283	Page 207.104g
16	Percent Allocation (Line 14 / Line 15)	12.3088%	

Affiliated Company Wages and Salaries

Shading denotes an input

Line		0
"Affiliated" Transmission Wages and Salaries		
#560 - 573		
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11 = 1 thru 10	Total Transmission	0
12 = Total "Affiliated" Wages and Salaries		
Less "Affiliated" Administrative and General Salaries		
#920 - 935		
13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
21 = 13 thru 20		0
22 = 12 less 21	Total "Affiliated" less A&G	0

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23

			TOTAL	
Participant	PTF Supporting Facilities	FERC Form 1	Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	332.(g); [332.1(g) for HWP]		
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			
	Comerford 115 kV Substation			
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	332.1(g); [332(g) for CL&P]		
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 337 line	332(g)		
	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310 line	330.1(n)		
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
Total =			0	0

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

NEPOOL Tariff Billing
NEPOOL Annual Transmission Revenue Requirements
per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3

Shading denotes an input

TOTAL

Submitted on: _____ RTO ROE filing

Revenue Requirements for (year): **Calendar Yr 2011** \$ **1,389,974**

Customer: _____

Customer's NABs Number: _____

Name of Participant responsible for customer's billing: _____

DUNs number of Participant responsible for customer's billing: _____

	<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>
Total of Attachment F - Sections A through I =	<u>1,389,975</u> (a)	_____ (f)
Total of Attachment F - Section J - Support Revenue	<u>0</u> (b)	_____ (g)
Total of Attachment F - Section K - Support Expense	<u>0</u> (c)	_____ (h)
Total of Attachment F - Section (L through O)	<u>(1)</u> (d)	_____ (i)
Sub Total - Sum (A through I) - J + K + (L through O)	<u>1,389,974</u> (e)=(a)-(b)+(c)+(d)	<u>-</u> (j)
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:		
		<u>1,389,974</u> (k) = (e) + (j)
Total of Attachment F - Section J - Pre-97 Support Revenue (from above)		
		<u>0</u> (b)
Total of Attachment F - Section J - Post-96 Support Revenue (from above-)		
		<u>0</u> (g)
Total of Attachment F - Section K - Post-96 Support Expense (from above)		
		<u>0</u> (h)
Voting Share Total for Participant's R Value:		
(for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)		<u><u>1,389,974</u></u> (l)=(k)+(b)+(g)-(h)

Annual Revenue Requirements of PTF Facilities
for costs in 2011

PTF Revenue Requirements

Worksheet 1 of 8

Shading denotes an input

		Attachment F		
		Reference	Total	Reference
Line N		Section:		
I. INVESTMENT BASE				
1	Transmission Plant	(A)(1)(a)	10,340,910	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	303,137	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		10,644,047	
5	Accumulated Depreciation	(A)(1)(d)	4,635,437	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	1,746,213	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	0	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	61,643	Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		4,324,040	
10	Prepayments	(A)(1)(h)	13,067	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	9,297	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	43,827	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		4,390,231	
II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	557,823	Worksheet 2
15	Depreciation Expense	(B)	296,813	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	0	Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)	(5,158)	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	189,878	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	0	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	(G)	254,758	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	95,861	Worksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	0	Worksheet 7
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)		
27	Revenue for ST Trans. Service Under NEPOOL Tar	(N)		
28	Transmission Rents Received from Electric Property	(O)		
29	Total Revenue Requirements (Line 14 thru 28)		1,389,975	

**Annual Revenue Requirements
for costs in 2011**

Shading denotes an input

	CAPITALIZATION 12/31/2011	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 213,145,046	49.15%	6.00%	2.95%	
PREFERRED STOCK	0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	220,478,764	50.86%	11.50%	5.85%	5.85%
TOTAL INVESTMENT	\$ 433,623,810	100.01%		8.80%	5.85%

Cost of Capital Rate=

(a) Weighted Cost of = 0.0880

$$\begin{aligned}
 \text{(b) Federal Income Tax} &= \frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec}}{\text{PTF Inv. Base}} \right) \times \text{Federal Income Tax Rate}}{\left(1 - \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}} \right)} \\
 &= \frac{0.0585 + \left(\frac{(5,158) + 0}{4,390,231} \right) \times 0.35}{1 - 0.35} \\
 &= 0.0308674
 \end{aligned}$$

$$\begin{aligned}
 \text{(c) State Income Tax} &= \frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec}}{\text{PTF Inv. Base}} \right) + \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}}}{\left(1 - \frac{\text{State Income Tax Rate}}{\text{State Income Tax Rate}} \right)} \times \text{State Income Tax Rate} \\
 &= \frac{0.0585 + \left(\frac{(5,158) + 0}{4,390,231} \right) + \frac{0.0308674}{0.085}}{1 - 0.085} \times 0.085 \\
 &= 0.0081927
 \end{aligned}$$

(a)+(b)+(c) **Cost of C** = 0.1270601

	(PTF)	
INVESTMENT BASE	\$ 4,390,231	From Worksheet 1
x Cost of Capital Rate	0.1270601	
= Investment Return and Ir	557,823	To Worksheet 1

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (
<u>Transmission Plant</u>						
1	50,793,621		50,793,621		10,340,910	Line 1, Workshe
2	42,651,318	3.4910% (a)	1,488,978	20.3587%	303,137	Page 207.90g
3			52,282,599		10,644,047	
4	0		0	20.3587%	0	Page 214.47d
<u>Transmission Accumulated Depreciation</u>						
5	22,263,587		22,263,587	20.3587%	4,532,577	Page 219.25b
6	14,472,474	3.4910% (a)	505,241	20.3587%	102,860	Page 219.28b
7			22,768,828		4,635,437	
<u>Transmission Accumulated Deferred Taxes</u>						
8	107,342,735	10.8079% (c)	11,601,495	20.3587%	2,361,914	Page 113.(57-65
9	(27,981,984)	10.8079% (c)	(3,024,265)	20.3587%	(615,701)	Page 111.82c
10			8,577,230		1,746,213	
11	0	10.8079% (c)	0	20.3587%	0	Page 111.81d
<u>Other Regulatory Assets</u>						
12	0	3.4910% (a)	0	20.3587%	0	Page 232.30e
13	1,598,748	10.8079% (c)	172,791	20.3587%	35,178	Page 232.21&25
14	1,202,747	10.8079% (c)	129,992	20.3587%	26,465	Page 278.1e
15	2,801,495		302,783		61,643	
16	1,838,565	3.4910% (a)	64,185	20.3587%	13,067	Page 111.57c
17	45,665		45,665	20.3587%	9,297	Page 227.8c
18	<u>Cash Working Capital</u>					
19	Operation & Maintenance Expense					Worksheet 1, Lir
20	Administrative & General Expense					Worksheet 1, Lir
21	Transmission Support Expense					Worksheet 1, Lir
22	Subtotal (line 19+20+21)					
23	0.125					x 45 / 360
24	43,827					

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

Shading denotes an input

Worksheet 4a of 4

		(2)		(4)		
Shading denotes an input		for costs in 2011				
Line No.		(1) Total	Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated
FERC Form 1 Reference for col (1)						
<u>Depreciation Expense</u>						
1	Transmission Depreciation	1,397,351		1,397,351	20.3587%	284,482
2	General Depreciation	1,734,979	3.4910% (a)	60,569	20.3587%	12,331
3	Total (line 1+2)			1,457,920		296,813
4	<u>Amortization of Loss on Reacquired Debt</u>	0	10.8079% (c)	0	20.3587%	0
5	<u>Amortization of Investment Tax Credits</u>	234,430	10.8079% (c)	25,337	20.3587%	5,158
<u>Property Taxes *</u>						
6	Transmission Property Taxes	6,522,613	10.8079% (c)	704,957	20.3587%	143,520
7	General Property Taxes	6,522,613	3.4910%	227,708	20.3587%	46,358
8	Total (line 6+7)			932,665		189,878
<u>Transmission Operation and Maintenance</u>						
9	Operation and Maintenance	32,955,723		32,955,723	20.3587%	6,709,357
10	Transmission of Electricity by Others - #565	31,301,329		31,301,329	20.3587%	6,372,544
11	Load Dispatching - #561	67,122		67,122	20.3587%	13,665
12	**Station Expenses & Rents - #562 / #567	335,924		335,924	20.3587%	68,390
13	O&M less lines 10, 11 & 12	1,251,348		1,251,348		254,758
<u>Transmission Administrative and General</u>						
14	Administrative and General	11,593,195				
15	less Property Insurance (#924)	447,229				
16	less Regulatory Commission Expenses (#928)	488,142				
17	less General Advertising Expense (#930.1)	66,032				
18	Subtotal [line 14 minus (15 thru 17)]	10,591,792	3.4910% (a)	369,764	20.3587%	75,279
19	PLUS Property Insurance alloc. using Plant Allocation	447,229	10.8079% (c)	48,336	20.3587%	9,841
20	PLUS Regulatory Comm. Exp. (FERC Assessments)	488,142	10.8079% (c)	52,758	20.3587%	10,741
21	PLUS Trans. Related General Advertising Expense	0	10.8079% (c)	0	20.3587%	0
22	Total A&G [line 18 plus (19 thru 21)]	11,527,163		470,858		95,861
23	<u>Payroll Tax Expense</u>		3.4910% (a)	0	20.3587%	0
Footnote (d)						
* Property Taxes functionalized per FERC Form 1; therefore, no need to use Plant Allocation Factor						
(a) Worksheet 5 of 8, line 11						
(b) Worksheet 5 of 8, line 3						
(c) Worksheet 5 of 8, line 16						
(d) Payroll taxes FERC Form 1, page 263.i ,263.1i						
	Federal Unemployment	0				
	FICA	0				
	Medicare	0				
	CT Unemployment					
	MA Unemployment					
	MA Universal Health					
	VT Unemployment	0				
	NH Unemployment	0				
	Total	0	To Line 23			

* Property Taxes functionalized per FERC Form 1; therefore, no need to use Plant Allocation Factor

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

(d) Payroll taxes FERC Form 1, page 263.i, 263.1i

Federal Unemployment	0
FICA	0
Medicare	0
CT Unemployment	
MA Unemployment	
MA Universal Health	
VT Unemployment	0
NH Unemployment	0
Total	0 To Line 23

** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments.

Shading denotes an input

Line
No.FERC Form 1
Reference**PTF Transmission Plant Allocation Factor****GMP**

1	PTF Transmission Investment	10,340,910	FIXED ASSET ROLL FORWARD
2	Total Transmission Investment	50,793,621	Page 207.58g
3	Percent Allocation (Line 1/Line 2)	20.3587%	

Transmission Wages and Salaries Allocation Factor

4	Direct Transmission Wages and Salaries	285,876	Page 354.21b
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 & 6a of 8
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	285,876	
7	Total Wages and Salaries	12,277,326	Page 354.28b
8	Administrative and General Wages and Salaries	4,088,494	Page 354.27b
9	Affiliated Company Wages and Salaries less A&G	0	Worksheet 6 & 6a of 8
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	8,188,832	
11	Percent Allocation (Line 6/Line 10)	3.4910%	

Plant Allocation Factor

12	Total Transmission Investment	50,793,621	Page 207.58g
13	plus Transmission-Related General Plant (Line 2 of Wkst. 3)		Page 207.99g
14	= Revised Numerator (Line 12 + Line 13)	50,793,621	
15	Total Plant in Service	469,969,105	Page 207.104g
16	Percent Allocation (Line 14 / Line 15)	10.8079%	

Affiliated Company Wages and Salaries

Shading denotes an input

Line		GMP
"Affiliated" Transmission Wages and Salaries #560 - 573		
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11 = 1 thru 10	Total Transmission	0
12 = Total "Affiliated" Wages and Salaries		0
Less "Affiliated" Administrative and General Salaries #920 - 935		
13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
21 = 13 thru 20		0
22 = 12 less 21	Total "Affiliated" less A&G	0

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23

			TOTAL	
Participant	PTF Supporting Facilities	FERC Form 1	Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	332.(g); [332.1(g) for HWP]		
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			
	Comerford 115 kV Substation			
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	332.1(g); [332(g) for CL&P]		
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 337 line	332(g)		
	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310 line	330.1(n)		
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
Total =			0	0

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

NEPOOL Tariff Billing
NEPOOL Annual Transmission Revenue Requirements
per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3

Shading denotes an input

TOTAL

Submitted on: December 31, 2011 RTO ROE filing

Revenue Requirements for (year): Calendar Yr 2011 \$ 257,639

Customer: Vermont Public Power Supply Authority

Customer's NABs Number:

Name of Participant responsible for customer's billing:

DUNs number of Participant responsible for customer's billing:

	<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>
Total of Attachment F - Sections A through I =	<u>257,639 (a)</u>	<u>(f)</u>
Total of Attachment F - Section J - Support Revenue	<u>0 (b)</u>	<u>(g)</u>
Total of Attachment F - Section K - Support Expense	<u>0 (c)</u>	<u>(h)</u>
Total of Attachment F - Section (L through O)	<u>0 (d)</u>	<u>(i)</u>
Sub Total - Sum (A through I) - J + K + (L through O)	<u>257,639 (e)=(a)-(b)+(c)+(d)</u>	<u>- (j)</u>
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:		<u>257,639 (k) = (e) + (j)</u>
Total of Attachment F - Section J - Pre-97 Support Revenue (from above)		<u>0 (b)</u>
Total of Attachment F - Section J - Post-96 Support Revenue (from above-)		<u>0 (g)</u>
Total of Attachment F - Section K - Post-96 Support Expense (from above)		<u>0 (h)</u>
Voting Share Total for Participant's R Value: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)		<u><u>257,639 (l)=(k)+(b)+(g)-(h)</u></u>

Annual Revenue Requirements of PTF Facilities
for costs in 2010

PTF Revenue Requirements

Worksheet 1 of 8

Shading denotes an input

		Attachment F		
Line N		Reference	Total	Reference
	<u>I. INVESTMENT BASE</u>	<u>Section:</u>		
1	Transmission Plant	(A)(1)(a)	3,038,991	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	19,837	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		3,058,828	
5	Accumulated Depreciation	(A)(1)(d)	2,748,824	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	0	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	0	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	0	Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		310,004	
10	Prepayments	(A)(1)(h)	0	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	0	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	21,419	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		331,423	
	<u>II. REVENUE REQUIREMENTS</u>			
14	Investment Return and Income Taxes	(A)	38,578	Worksheet 2
15	Depreciation Expense	(B)	10,468	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	0	Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)	0	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	37,245	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	0	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	(G)	49,064	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	122,284	Worksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	0	Worksheet 7
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)		
27	Revenue for ST Trans. Service Under NEPOOL Tar	(N)		
28	Transmission Rents Received from Electric Property	(O)		
29	Total Revenue Requirements (Line 14 thru 28)		257,639	

Annual Revenue Requirements
for costs in 2011

Shading denotes an input

	CAPITALIZATION 12/31/2011	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 0	0.00%	0.00%	0.00%	
PREFERRED STOCK	0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	503,709	100.01%	11.64%	11.64%	11.64%
TOTAL INVESTMENT	\$ 503,709	100.01%		11.64%	11.64%

Cost of Capital Rate=

(a) Weighted Cost of = 0.1164

(b) Federal Income Tax =
$$\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec}}{\text{PTF Inv. Base}} \right) \times \text{Federal Income Tax Rate}}{\left(1 - \text{Federal Income Tax Rate} \right)}$$

=
$$\frac{0.1164 + \left(\frac{0 + 0}{331,423} \right) \times 0}{\left(1 - 0 \right)}$$

= 0.0000000

(c) State Income Tax =
$$\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec}}{\text{PTF Inv. Base}} \right) + \text{Federal Income Tax}}{\left(1 - \text{State Income Tax Rate} \right)} \times \text{State Income Tax Rate}$$

=
$$\frac{0.1164 + \left(\frac{0 + 0}{331,423} \right) + 0.0000000}{\left(1 - 0 \right)} \times 0$$

= 0.0000000

(a)+(b)+(c) Cost of C = 0.1164000

(PTF)

INVESTMENT BASE \$ 331,423 From Worksheet 1

x Cost of Capital Rate 0.1164000

= Investment Return and Interest 38,578 To Worksheet 1

Sheet: Worksheet 3

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (
<u>Transmission Plant</u>						
1	3,038,991		3,038,991		3,038,991	Line 1, Workshe
2	19,837	100.0000% (a)	19,837	100.0000%	19,837	Page 207.90g
3	3,058,828		3,058,828		3,058,828	
4	0		0	100.0000%	0	Page 214.47d
<u>Transmission Accumulated Depreciation</u>						
5	2,728,987		2,728,987	100.0000%	2,728,987	Page 219.25b
6	19,837	100.0000% (a)	19,837	100.0000%	19,837	Page 219.28b
7	2,748,824		2,748,824		2,748,824	
<u>Transmission Accumulated Deferred Taxes</u>						
8	0	100.0000% (c)	0	100.0000%	0	Page 113.(57-65
9	0	100.0000% (c)	0	100.0000%	0	Page 111.82c
10			0		0	
11	0	100.0000% (c)	0	100.0000%	0	Page 111.81d
<u>Other Regulatory Assets</u>						
12	0	100.0000% (a)	0	100.0000%	0	Page 232.30e
13	0	100.0000% (c)	0	100.0000%	0	Page 232.21&23
14	0	100.0000% (c)	0	100.0000%	0	Page 278.1e
15	0		0		0	
16	0	100.0000% (a)	0	100.0000%	0	Page 111.57c
17	0		0	100.0000%	0	Page 227.8c
18	<u>Cash Working Capital</u>					
19	Operation & Maintenance Expense					Worksheet 1, Lir
20	Administrative & General Expense					Worksheet 1, Lir
21	Transmission Support Expense					Worksheet 1, Lir
22	Subtotal (line 19+20+21)					
23	0.125					x 45 / 360
24	21,419					

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

Shading denotes an input

Worksheet 4

Worksheet 4a of 4

Line No.	(2)		(4)		(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)	
	(1) Total	for costs in 2005 Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	PTF Allocation Factor (b)			
<u>Depreciation Expense</u>							
1	Transmission Depreciation	10,468		10,468	100.0000%	10,468	Page 336.7b
2	General Depreciation	0	100.0000% (a)	0	100.0000%	0	Page 336.10b
3	Total (line 1+2)			10,468		10,468	
<u>Amortization of Loss on Reacquired Debt</u>							
4		0	100.0000% (c)	0	100.0000%	0	Page 117.64c
<u>Amortization of Investment Tax Credits</u>							
5		0	100.0000% (c)	0	100.0000%	0	Page 266.8f
<u>Property Taxes *</u>							
6	Transmission Property Taxes	37,245	100.0000% (c)	37,245	100.0000%	37,245	Page 262-263 FN.1-2
7	General Property Taxes	0	100.0000%	0	100.0000%	0	Page 262-263 FN.1-2
8	Total (line 6+7)	37,245		37,245		37,245	
<u>Transmission Operation and Maintenance</u>							
9	Operation and Maintenance	49,064		49,064	100.0000%	49,064	Page 321.112b
10	Transmission of Electricity by Others - #565	0		0	100.0000%	0	Page 321.96b
11	Load Dispatching - #561	0		0	100.0000%	0	Page 321.84b
12	**Station Expenses & Rents - #562 / #567	0		0	100.0000%	0	Page 321.85b & .90b
13	O&M less lines 10, 11 & 12	49,064		49,064		49,064	
<u>Transmission Administrative and General</u>							
14	Administrative and General	122,285					Page 323.197b
15	less Property Insurance (#924)	17,224					Page 323.185b
16	less Regulatory Commission Expenses (#928)	0					Page 323.189b
17	less General Advertising Expense (#930.1)	0					Page 323.191b
18	Subtotal [line 14 minus (15 thru 17)]	105,060	100.0000% (a)	105,060	100.0000%	105,060	
19	PLUS Property Insurance alloc. using Plant Allocator	17,224	100.0000% (c)	17,224	100.0000%	17,224	
20	PLUS Regulatory Comm. Exp. (FERC Assessments)	0	100.0000% (c)	0	100.0000%	0	
21	PLUS Trans. Related General Advertising Expense	0	100.0000% (c)	0	100.0000%	0	
22	Total A&G [line 18 plus (19 thru 21)]	122,285		122,284		122,284	
23	Payroll Tax Expense		100.0000% (a)	0	100.0000%	0	Footnote (d)

* Property Taxes functionalized per FERC Form 1; therefore, no need to use Plant Allocation Factor

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

(d) Payroll taxes FERC Form 1, page 263.i ,263.1i

Federal Unemployment	0
FICA	0
Medicare	0
CT Unemployment	
MA Unemployment	
MA Universal Health	
VT Unemployment	0
NH Unemployment	0
Total	0

To Line 23

* Property Taxes functionalized per FERC Form 1; therefore, no need to use Plant Allocation Factor

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

(d) Payroll taxes FERC Form 1, page 263.i, 263.1i

Federal Unemployment

FICA

Medicare

CT Unemployment

MA Unemployment

MA Universal Health

VT Unemployment

NH Unemployment

Total

To Line 23

** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments.

Shading denotes an input

Line
No.

FERC Form 1
Reference

PTF Transmission Plant Allocation Factor

1	PTF Transmission Investment	3,038,991	NEPOOL Catalog
2	Total Transmission Investment	3,038,991	Page 207.58g
3	Percent Allocation (Line 1/Line 2)	100.0000%	

Transmission Wages and Salaries Allocation Factor

4	Direct Transmission Wages and Salaries	837	Page 354.21b
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 & 6a of 8
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	837	
7	Total Wages and Salaries	38,713	Page 354.28b
8	Administrative and General Wages and Salaries	37,877	Page 354.27b
9	Affiliated Company Wages and Salaries less A&G	0	Worksheet 6 & 6a of 8
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	837	
11	Percent Allocation (Line 6/Line 10)	100.0000%	

Plant Allocation Factor

12	Total Transmission Investment	3,038,991	Page 207.58g
13	plus Transmission-Related General Plant (Line 2 of Wkst. 3)	19,837	Page 207.99g
14	= Revised Numerator (Line 12 + Line 13)	3,058,828	
15	Total Plant in Service	3,058,828	Page 207.104g
16	Percent Allocation (Line 14 / Line 15)	100.0000%	

Affiliated Company Wages and Salaries

Shading denotes an input

Line		0	
"Affiliated" Transmission Wages and Salaries #560 - 573			
1	560	0	NA for VPP
2	562	0	
3	564	0	
4	566	0	
5	568	0	
6	569	0	
7	570	0	
8	571	0	
9	572	0	
10	573	0	
11 = 1 thru 10	Total Transmission	0	
12 = Total "Affiliated" Wages and Salaries			
Less "Affiliated" Administrative and General Salaries #920 - 935			
13	920	0	
14	921	0	
15	923	0	
16	925	0	
17	926	0	
18	928	0	
19	930	0	
20	935	0	
21 = 13 thru 20		0	
22 = 12 less 21	Total "Affiliated" less A&G	0	

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23

			TOTAL	
Participant	PTF Supporting Facilities	FERC Form 1	Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	332.(g); [332.1(g) for HWP]		
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			
	Comerford 115 kV Substation			
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	332.1(g); [332(g) for CL&P]		
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 337 line	332(g)		
	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310 line	330.1(n)		
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
Total =			0	0

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

NEPOOL Tariff Billing
NEPOOL Annual Transmission Revenue Requirements
per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3

Shading denotes an input

TOTAL

Submitted on: May 10, 2012 RTO ROE filing

Revenue Requirements for (year): Calendar Yr 2011 \$ 280,924

Customer: Burlington Electric Department

Customer's NABs Number:

Name of Participant responsible for customer's billing:

DUNs number of Participant responsible for customer's billing:

	<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>
Total of Attachment F - Sections A through I =	<u>280,925</u> (a)	<u></u> (f)
Total of Attachment F - Section J - Support Revenue	<u>0</u> (b)	<u></u> (g)
Total of Attachment F - Section K - Support Expense	<u>0</u> (c)	<u></u> (h)
Total of Attachment F - Section (L through O)	<u>(1)</u> (d)	<u></u> (i)
Sub Total - Sum (A through I) - J + K + (L through O)	<u>280,924</u> (e)=(a)-(b)+(c)+(d)	<u>-</u> (j)
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:		<u>280,924</u> (k) = (e) + (j)
Total of Attachment F - Section J - Pre-97 Support Revenue (from above)		<u>0</u> (b)
Total of Attachment F - Section J - Post-96 Support Revenue (from above-)		<u>0</u> (g)
Total of Attachment F - Section K - Post-96 Support Expense (from above)		<u>0</u> (h)
Voting Share Total for Participant's R Value: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)		<u><u>280,924</u></u> (l)=(k)+(b)+(g)-(h)

Annual Revenue Requirements of PTF Facilities
for costs in 2011

PTF Revenue Requirements
Worksheet 1 of 8

Shading denotes an input

		Attachment F		
Line N		<u>Reference</u>	<u>Total</u>	<u>Reference</u>
	I. INVESTMENT BASE	<i>Section:</i>		
1	Transmission Plant	(A)(1)(a)	2,656,477	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	0	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		<u>2,656,477</u>	
5	Accumulated Depreciation	(A)(1)(d)	853,498	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	0	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	0	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	0	Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		<u>1,802,979</u>	
10	Prepayments	(A)(1)(h)	0	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	0	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	<u>4,179</u>	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		<u><u>1,807,158</u></u>	
	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	148,548	Worksheet 2
15	Depreciation Expense	(B)	53,813	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	0	Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)	0	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	45,130	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	0	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	(G)	30,689	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	2,745	Worksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	0	Worksheet 7
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)		
27	Revenue for ST Trans. Service Under NEPOOL Tar	(N)		
28	Transmission Rents Received from Electric Property	(O)		
29	Total Revenue Requirements (Line 14 thru 28)		<u><u>280,925</u></u>	

**Annual Revenue Requirements
for costs in 2011**

Shading denotes an input

	CAPITALIZATION 12/31/2011	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 74,240,274	57.84%	5.72%	3.31%	
PREFERRED STOCK	0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	54,106,201	42.17%	11.64%	4.91%	4.91%
TOTAL INVESTMENT	\$ 128,346,475	100.01%		8.22%	4.91%

Cost of Capital Rate=

(a) Weighted Cost of = 0.0822

(b) Federal Income Tax =
$$\frac{R.O.E. + \left(\frac{PTF \text{ Inv. (Tax Credit)} + \frac{Eq. AFUDC \text{ of Deprec}}{PTF \text{ Inv. Base}} \right)}{1} \times \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}}$$

=
$$\frac{0.0491 + \left(\frac{0 + \frac{0}{1,807,158}}{1} \right) \times \frac{0}{0}}{0.000000}$$

(c) State Income Tax =
$$\frac{R.O.E. + \left(\frac{PTF \text{ Inv. (Tax Credit)} + \frac{Eq. AFUDC \text{ of Deprec}}{PTF \text{ Inv. Base}} \right) + \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}}}{1} \times \frac{\text{State Income Tax Rate}}{\text{State Income Tax Rate}}$$

=
$$\frac{0.0491 + \left(\frac{0 + \frac{0}{1,807,158}}{1} \right) + \frac{0.000000}{0}}{0.000000}$$

(a)+(b)+(c) **Cost of C** = 0.0822000

(PTF)

INVESTMENT BASE \$ 1,807,158 From Worksheet 1

x Cost of Capital Rate 0.0822000

= Investment Return and Ir 148,548 To Worksheet 1

Shading denotes an input

Line No.	(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (
<u>Transmission Plant</u>						
1	4,939,298		4,939,298		2,656,477	Line 1, Workshe
2	11,941,447	0.0000% (a)	0	53.7825%	0	Page 207.90g
3	16,880,745		4,939,298		2,656,477	
4	0		0	53.7825%	0	Page 214.47d
<u>Transmission Accumulated Depreciation</u>						
5	1,586,943		1,586,943	53.7825%	853,498	Page 219.25b
6	6,422,677	0.0000% (a)	0	53.7825%	0	Page 219.28b
7	8,009,620		1,586,943		853,498	
<u>Transmission Accumulated Deferred Taxes</u>						
8	0	3.8450% (c)	0	53.7825%	0	Page 113.(57-65
9	0	3.8450% (c)	0	53.7825%	0	Page 111.82c
10			0		0	
11	0	3.8450% (c)	0	53.7825%	0	Page 111.81d
<u>Other Regulatory Assets</u>						
12	0	0.0000% (a)	0	53.7825%	0	Page 232.30e
13	0	3.8450% (c)	0	53.7825%	0	Page 232.21&23
14	0	3.8450% (c)	0	53.7825%	0	Page 278.1e
15	0		0		0	
16	0	0.0000% (a)	0	53.7825%	0	Page 111.57c
17	0		0	53.7825%	0	Page 227.8c
<u>Cash Working Capital</u>						
18					30,689	Worksheet 1, Lir
19					2,745	Worksheet 1, Lir
20					0	Worksheet 1, Lir
21					0	
22					33,434	
23					0.125	x 45 / 360
24					4,179	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

Shading denotes an input

Worksheet 4		(2)		(4)		
Shading denotes an input						
		for costs in 2005				
		Wage/Plant				
		Allocation	(3) = (1)*(2)	PTF	(5) = (3)*(4)	
		Factors	Transmission	Allocation	PTF	FERC Form 1
line	(1)		Allocated	Factor (b)	Allocated	Reference for col (1)
No.	Total					
<u>Depreciation Expense</u>						
1	Transmission Depreciation	100,056	100,056	53.7825%	53,813	Page 336.7b
2	General Depreciation	277,460	0.0000% (a) 0	53.7825%	0	Page 336.10b
3	Total (line 1+2)	377,516	100,056		53,813	
<u>Amortization of Loss on Reacquired Debt</u>						
4		0	3.8450% (c) 0	53.7825%	0	Page 117.64c
<u>Amortization of Investment Tax Credits</u>						
5		0	3.8450% (c) 0	53.7825%	0	Page 266.8f
<u>Property Taxes *</u>						
6	Transmission Property Taxes	30,639	3.8450% (c) 1,178	53.7825%	634	Page 262-263 FN.1-2
7	General Property Taxes	2,151,737	3.8450% 82,734	53.7825%	44,496	Page 262-263 FN.1-2
8	Total (line 6+7)	2,182,376	83,912		45,130	
<u>Transmission Operation and Maintenance</u>						
9	Operation and Maintenance	5,093,562	5,093,562	53.7825%	2,739,445	Page 321.112b
10	Transmission of Electricity by Others - #565	5,036,501	5,036,501	53.7825%	2,708,756	Page 321.96b
11	Load Dispatching - #561	0	0	53.7825%	0	Page 321.84b
12	**Station Expenses & Rents - #562 / #567	0	0	53.7825%	0	Page 321.85b & .90b
13	O&M less lines 10, 11 & 12	57,061	57,061		30,689	
<u>Transmission Administrative and General</u>						
14	Administrative and General	3,113,486				Page 323.197b
15	less Property Insurance (#924)	72,212				Page 323.185b
16	less Regulatory Commission Expenses (#928)	60,496				Page 323.189b
17	less General Advertising Expense (#930.1)	0				Page 323.191b
18	Subtotal [line 14 minus (15 thru 17)]	2,980,779	0.0000% (a) 0	53.7825%	0	
19	PLUS Property Insurance alloc. using Plant Allocator	72,212	3.8450% (c) 2,777	53.7825%	1,494	
20	PLUS Regulatory Comm. Exp. (FERC Assessments)	60,496	3.8450% (c) 2,326	53.7825%	1,251	
21	PLUS Trans. Related General Advertising Expense	0	3.8450% (c) 0	53.7825%	0	
22	Total A&G [line 18 plus (19 thru 21)]	3,113,486	5,103		2,745	
23	Payroll Tax Expense	685,501	0.0000% (a) 0	53.7825%	0	Footnote (d)
* Property Taxes functionalized per FERC Form 1; therefore, no need to use Plant Allocation Factor						
(a) Worksheet 5 of 8, line 11						
(b) Worksheet 5 of 8, line 3						
(c) Worksheet 5 of 8, line 16						
(d) Payroll taxes FERC Form 1, page 263.i ,263.1i						
	Federal Unemployment	551,409				
	FICA	126,824				
	Medicare	0				
	CT Unemployment					
	MA Unemployment					
	MA Universal Health					
	VT Unemployment	7,268				
	NH Unemployment	0				
	Total	685,501	To Line 23			

** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments.

Shading denotes an input

Line
No.FERC Form 1
Reference**PTF Transmission Plant Allocation Factor**

1	PTF Transmission Investment	2,656,477	NEPOOL Catalog
2	Total Transmission Investment	4,939,298	Page 207.58g
3	Percent Allocation (Line 1/Line 2)	53.7825%	

Transmission Wages and Salaries Allocation Factor

4	Direct Transmission Wages and Salaries	0	Page 354.21b
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 & 6a of 8
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	0	
7	Total Wages and Salaries	7,485,080	Page 354.28b
8	Administrative and General Wages and Salaries	1,487,451	Page 354.27b
9	Affiliated Company Wages and Salaries less A&G	0	Worksheet 6 & 6a of 8
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	5,997,629	
11	Percent Allocation (Line 6/Line 10)	0.0000%	

Plant Allocation Factor

12	Total Transmission Investment	4,939,298	Page 207.58g
13	plus Transmission-Related General Plant (Line 2 of Wkst. 3)	317,146	Page 207.99g
14	= Revised Numerator (Line 12 + Line 13)	5,256,444	
15	Total Plant in Service	136,708,416	Page 207.104g
16	Percent Allocation (Line 14 / Line 15)	3.8450%	

Affiliated Company Wages and Salaries

Shading denotes an input

Line		0
"Affiliated" Transmission Wages and Salaries		
#560 - 573		
1	560	0
2	562	0
3	564	0
4	566	0
5	568	0
6	569	0
7	570	0
8	571	0
9	572	0
10	573	0
11 = 1 thru 10	Total Transmission	0
12 = Total "Affiliated" Wages and Salaries		
Less "Affiliated" Administrative and General Salaries		
#920 - 935		
13	920	0
14	921	0
15	923	0
16	925	0
17	926	0
18	928	0
19	930	0
20	935	0
21 = 13 thru 20		0
22 = 12 less 21	Total "Affiliated" less A&G	0

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23

			TOTAL	
Participant	PTF Supporting Facilities	FERC Form 1	Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	332.(g); [332.1(g) for HWP]		
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			
	Comerford 115 kV Substation			
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	332.1(g); [332(g) for CL&P]		
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 337 line	332(g)		
	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310 line	330.1(n)		
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
Total =			0	0

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

NEPOOL Tariff Billing
NEPOOL Annual Transmission Revenue Requirements
per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3

Shading denotes an input

TOTAL

Submitted on: _____ RTO ROE filing

Revenue Requirements for (year): **Calendar Yr 2011 \$ 49,153**

Customer: **Village of Johnson**

Customer's NABs Number: _____

Name of Participant responsible for customer's billing: _____

DUNS number of Participant responsible for customer's billing: _____

	<u>Pre-97 Revenue Requirements</u>	<u>Post-96 Revenue Requirements</u>	
Total of Attachment F - Sections A through I =	49,154 (a)	_____ (f)	
Total of Attachment F - Section J - Support Revenue	0 (b)	_____ (g)	N/A for Johnson
Total of Attachment F - Section K - Support Expense	0 (c)	_____ (h)	N/A for Johnson
Total of Attachment F - Section (L through O)	(1) (d)	_____ (i)	N/A for Johnson
Sub Total - Sum (A through I) - J + K + (L through O)	49,153 (e)=(a)-(b)+(c)+(d)	- (j)	

Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements
and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff

49,153 (k) = (e) + (j)

Total of Attachment F - Section J - Pre-97 Support Revenue (from above)	0 (b)	N/A for Johnson
Total of Attachment F - Section J - Post-96 Support Revenue (from above)	0 (g)	N/A for Johnson
Total of Attachment F - Section K - Post-96 Support Expense (from above)	0 (h)	N/A for Johnson

Voting Share Total for Participant's R Value: **49,153 (l)=(k)+(b)+(g)-(h)**
(for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)

Village of Johnson
Annual Revenue Requirements of PTF Facilities
for costs in 2011

PTF Revenue Requirements

Worksheet 1 of 8

Shading denotes an input

Attachment F

Line N		Reference	Total	Reference	
	I. <u>INVESTMENT BASE</u>	Section:			
1	Transmission Plant	(A)(1)(a)	117,017	Worksheet 3, line 1 column 5	
2	General Plant	(A)(1)(b)	0	Worksheet 3, line 2 column 5	
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3, line 4 column 5	
4	Total Plant (Lines 1+2+3)		117,017		
5	Accumulated Depreciation	(A)(1)(d)	76,060	Worksheet 3, line 7 column 5	
6	Accumulated Deferred Income Taxes	(A)(1)(e)	0	Worksheet 3, line 10 column 5	N/A for Johnson
7	Loss On Reacquired Debt	(A)(1)(f)	0	Worksheet 3, line 11 column 5	N/A for Johnson
8	Other Regulatory Assets	(A)(1)(g)	0	Worksheet 3, line 14 column 5	N/A for Johnson
9	Net Investment (Line 4-5-6+7+8)		40,957		
10	Prepayments	(A)(1)(h)	0	Worksheet 3, line 15 column 5	N/A for Johnson
11	Materials & Supplies	(A)(1)(i)	0	Worksheet 3, line 16 column 5	N/A for Johnson
12	Cash Working Capital	(A)(1)(j)	5,007	Worksheet 3, line 23 column 5	
13	Total Investment Base (Line 9+10+11+12)		45,964		
	II. <u>REVENUE REQUIREMENTS</u>				
14	Investment Return and Income Taxes	(A)	4,459	Worksheet 2	
15	Depreciation Expense	(B)	2,925	Worksheet 4, line 3 column 5	
16	Amortization of Loss on Reacquired Debt	(C)	0	Worksheet 4, line 4 column 5	N/A for Johnson
17	Investment Tax Credit	(D)	0	Worksheet 4, line 5 column 5	N/A for Johnson
18	Property Tax Expense	(E)	1,711	Worksheet 4, line 8 column 5	
19	Payroll Tax Expense	(F)	0	Worksheet 4, line 23 column 5	N/A for Johnson
20	Operation & Maintenance Expense	(G)	39,172	Worksheet 4, line 13 column 5	
21	Administrative & General Expense	(H)	887	Worksheet 4, line 16 column 5	
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7	N/A for Johnson
23	Transmission Support Revenue	(J)	0	Worksheet 7	N/A for Johnson
24	Transmission Support Expense	(K)	0	Worksheet 7	N/A for Johnson
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7	N/A for Johnson
26	Transmission Related Taxes and Fees Charge	(M)			FF 1 Page 263
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)			
28	Transmission Rents Received from Electric Property	(O)			Rev Rent 4000-454122
29	Total Revenue Requirements (Line 14 thru 28)		49,154		

Village of Johnson
Annual Revenue Requirements
for costs in 2011

Shading denotes an input

	CAPITALIZATION 12/31/2011	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	\$ 592,754	25.71%	4.10%	1.05%	
PREFERRED STOCK	0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	1,712,962	74.30%	11.64%	8.65%	8.65%
TOTAL INVESTMENT RE	\$ 2,305,716	100.01%		9.70%	8.65%

Cost of Capital Rate=

(a) Weighted Cost of Cap = 0.0970

(b) Federal Income Tax =
$$\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec}}{\text{PTF Inv. Base}} \right) \times \text{Federal Income Tax Rate}}{\left(\frac{0.0865}{1} + \frac{0}{1} + \frac{0}{45,964} \right) - \frac{0}{0}}$$

= 0.0000000

N/A for John

(c) State Income Tax =
$$\frac{\text{R.O.E.} + \left(\frac{\text{PTF Inv. (Tax Credit)} + \text{Eq. AFUDC of Deprec}}{\text{PTF Inv. Base}} \right) + \frac{\text{Federal Income Tax}}{\text{State Income Tax Rate}}}{\left(\frac{0.0865}{1} + \frac{0}{1} + \frac{0}{45,964} \right) - \frac{0.0000000}{0}} \times \text{State Income Tax Rate}$$

= 0.0000000

(a)+(b)+(c) **Cost of Capit** = 0.0970000

(PTF)

INVESTMENT BASE \$ 45,964 From Worksheet 1

x Cost of Capital Rate 0.0970000

= Investment Return and Income 4,459 To Worksheet 1

Shading denotes an input

	(1) Total	fo (2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
<u>Transmission Plant</u>						
Transmission Plant	117,017		117,017		117,017	Line 1, Worksheet 5
General Plant	0	100.0000% (a)	0	100.0000%	0	Page 207.90g
Total (line 1+2)	117,017		117,017		117,017	
<u>Transmission Plant Held for Future Use</u>	0		0	100.0000%	0	Page 214.47d N/A for Johnson
<u>Transmission Accumulated Depreciation</u>						
Transmission Accum. Depreciation	76,060		76,060	100.0000%	76,060	Page 219.25b
General Plant Accum. Depreciation	0	100.0000% (a)	0	100.0000%	0	Page 219.28b
Total (line 5+6)	76,060		76,060		76,060	
<u>Transmission Accumulated Deferred Taxes</u>						
Accumulated Deferred Taxes (281-283)	0	100.0000% (c)	0	100.0000%	0	Page 113.57d N/A for Johnson
Accumulated Deferred Taxes (190)	0	100.0000% (c)	0	100.0000%	0	Page 111.82c N/A for Johnson
Total (line 8+9)			0		0	
<u>Transmission loss on Reacquired Debt</u>	0	100.0000% (c)	0	100.0000%	0	Page 111.67d N/A for Johnson
<u>Other Regulatory Assets</u>						
FAS 106	0	100.0000% (a)	0	100.0000%	0	Page 232.30e N/A for Johnson
FAS 109	0	100.0000% (c)	0	100.0000%	0	Page 232.1,2,3f N/A for Johnson
Other Regulatory Liabilities (254.DK)	0	100.0000% (c)	0	100.0000%	0	Page 278.1,2f N/A for Johnson
Total (line 12+13+14)	0		0		0	
<u>Transmission Prepayments</u>	0	100.0000% (a)	0	100.0000%	0	Page 110.57c N/A for Johnson
<u>Transmission Materials and Supplies</u>	0		0	100.0000%	0	Page 227.8c N/A for Johnson
<u>Cash Working Capital</u>						
Operation & Maintenance Expense					39,172	Worksheet 1, Line 20
Administrative & General Expense					887	Worksheet 1, Line 21
Transmission Support Expense					0	Worksheet 1, Line 24
Subtotal (line 19+20+21)					40,059	
					0.125	x 45 / 360
Total (line 22 * line 23)					5,007	

(a) Worksheet 5 of 8, line 11

(b) Worksheet 5 of 8, line 3

(c) Worksheet 5 of 8, line 16

(4)

Total 0 To Line 23

0	Comerford - Take out because - Support Payment included on Worksheet 7
0	net

Shading denotes an input

for costs in 2011

Line
No.FERC Form 1
Reference**PTF Transmission Plant Allocation Factor****Johnson**

1	PTF Transmission Investment	117,017	NEPOOL Catalog
2	Total Transmission Investment	117,017	Page 207.58g
3	Percent Allocation (Line 1/Line 2)	<u>100.0000%</u>	

Transmission Wages and Salaries Allocation Factor

4	Direct Transmission Wages and Salaries	38	Page 354.21b
5	Affiliated Company Transmission Wages and Salaries	<u>0</u>	Worksheet 6 & 6a o N/A for Johnson
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	38	
7	Total Wages and Salaries	38	Page 354.28b
8	Administrative and General Wages and Salaries	<u>0</u>	Page 354.27b N/A for Johnson
9	Affiliated Company Wages and Salaries less A&G	<u>0</u>	Worksheet 6 & 6a o N/A for Johnson
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	38	
11	Percent Allocation (Line 6/Line 10)	100.00%	

Plant Allocation Factor

12	Total Transmission Investment	117,017	Page 207.58g
13	plus Transmission-Related General Plant (Line 2 of Wkst. 3)	<u></u>	Worksheet 3, Line 2
14	= Revised Numerator (Line 12 + Line 13)	117,017	
15	Total Plant in Service	117,017	Page 207.95g
16	Percent Allocation (Line 14 / Line 15)	<u>100.0000%</u>	

Affiliated Company Wages and Salaries

Shading denotes an input

Line		Johnson	N/A for Johnson Johnson has no "affiliated" wages & salaries
"Affiliated" Transmission Wages and Salaries			
#560 - 573			
1	560		
2	562		
3	564		
4	566		
5	568		
6	569		
7	570		
8	571		
9	572		
10	573		
11 = 1 thru 10	Total Transmission	0	
12 = Total "Affiliated" Wages and Salaries		0	
Less "Affiliated" Administrative and General Salaries			
#920 - 935			
13	920	0	
14	921	0	
15	923	0	
16	925	0	
17	926	0	
18	928	0	
19	930	0	
20	935	0	
21 = 13 thru 20		0	
22 = 12 less 21 Total "Affiliated" less A&G		0	

Input Revenues associated with the PTF Supporting Facilities in columns (a) and expenses associated with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and 24.

Participant	PTF Supporting Facilities	FERC Form 1	TOTAL	
			Revenues (a)	Expenses (b)
BECO	345 kV Sherman - Medway 336 line			
	115 kV Somerville 402 Substation			
	115/345 kV North Cambridge 509 Substation			
	345 kV Golden Hills -Mystic 389 (x&y) line			
	West Medway 345 kV breaker			
	115 kV Millbury-Medway 201 line			
	HQ Phase II - AC in MA	332.(g); [332.1(g) for HWP]		
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	345 kV Buxton-South Gorham 386 line			
	115 kV Wyman 164-167 lines			
	115 kV Maine Yankee transmission	332.1(g)		
EUA	345 kV Carver - Walpole 331 line			
	345 kV Medway - Bridgewater 344 Line			
	Northern Rhode Island transmission			
NEP	Chester SVC			
	Comerford 115 kV Substation			
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	332.1(g); [332(g) for CL&P]		
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 399	332(g)		
	115 kV Read - Washington V148 line			
NU	345 kV 363, 369 and 394 Seabrook lines			
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310 line	330.1(n)		
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
Total =			0	0

N/A for Johnson

Johnson has no "affiliated" wages & salaries

Amount by which Support Expense exceeds Support Revenues
(To Worksheet 3, Line 21, Column 5)

Attachment 3

Summary of Forecasted Transmission Revenue Requirements Associated with Projected PTF and CWIP Additions for 2012

**June 1, 2012 RNS Rates
Regional Forecast Summary**

	(A)	(B)	(C)	(D) = (C) / Load
	Participating Transmission Owner	Total Estimated 2012 PTF Capital Costs (\$)	Forecasted PTF Revenue Requirement (\$)	6/1/12 RNS Rate Impact (\$/kW-yr.)
1	Northeast Utilities	\$ 365,642,000	\$ 61,506,000	3.04812
2	Central Maine Power	\$ 364,053,174	\$ 54,449,814	2.69843
3	New England Power	\$ 236,721,611	\$ 37,048,813	1.83607
4	United Illuminating	\$ 70,000,000	\$ 13,987,815	0.69321
5	Bangor Hydro	\$ 76,225,077	\$ 12,563,562	0.62263
6	NSTAR	\$ 88,016,000	\$ 12,060,057	0.59767
7	Vermont Transco	\$ 40,000,000	\$ 7,028,376	0.34831
8	Connecticut Transmission Municipal Electric Energy Cooperative (a)	\$ 51,339,736	\$ 1,605,619	0.07957
9	New Hampshire Transmission	\$ 6,000,000	\$ 1,113,975	0.05521
10	All Remaining PTO's	\$ 7,450,190	\$ 1,506,654	0.07467
11	Total (Sum Line 1 -10)	\$ 1,305,447,788	\$ 202,870,685	10.05388
2011 RTO-NE 12 -CP RNS Load:			20,178,343	kW
(a) Not a projected PTF addition; current PTF facility cost used to calculate additional revenue requirements to establish an initial full calendar year of cost data.				

Attachment 4

Annual True-up Summary

June 1, 2012 RNS Rates Annual True-up Summary													
	(A)		(B)		(C)		(D) = (C) - (B)		(E)		(F) = (D) + (E)		(G) = (F) / Load
	Participating Transmission Owner		RNS Rev Req's 2010 Actual + 2011 Forecast (As Billed)		RNS Rev Req'ts 2011 Actual (For True-up)		Difference (overcollection), undercollection		Interest on Difference		Annual True Up and Associated Interest		6/1/12 RNS Rate Impact (\$/kW-yr.)
1	NGRID		\$ 215,381,694		\$ 225,754,345		\$ 10,372,651		\$ 345,652		\$ 10,718,303		0.53118
2	VT Transco	(a)	\$ 107,757,288		\$ 113,775,524		\$ 6,018,236		\$ 187,567		\$ 6,205,803		0.30755
3	UI		\$ 91,968,162		\$ 96,098,191		\$ 4,130,029		\$ 137,626		\$ 4,267,655		0.21150
4	NSTAR		\$ 160,098,305		\$ 160,479,385		\$ 381,080		\$ 12,699		\$ 393,779		0.01951
5	CTMEEC		\$ 7,378,335		\$ 6,489,885		\$ (888,450)		\$ (29,606)		\$ (918,056)		(0.04550)
6	NHT		\$ 11,754,475		\$ 10,431,589		\$ (1,322,886)		\$ (44,083)		\$ (1,366,969)		(0.06774)
7	BHE		\$ 41,187,778		\$ 38,247,494		\$ (2,940,284)		\$ (97,980)		\$ (3,038,264)		(0.15057)
8	NU	(a)	\$ 602,753,957		\$ 571,810,537		\$ (30,943,420)		\$ (1,032,984)		\$ (31,976,404)		(1.58469)
9	CMP		\$ 162,225,453		\$ 128,068,272		\$ (34,157,181)		\$ (1,138,231)		\$ (35,295,412)		(1.74917)
10	All Remaining PTO's		\$ 7,811,560		\$ 8,462,205		\$ 650,645		\$ 21,690		\$ 672,335		0.03332
11	Total (Sum of Line 1-10)		<u>\$ 1,408,317,007</u>		<u>\$ 1,359,617,427</u>		<u>\$ (48,699,580)</u>		<u>\$ (1,637,650)</u>		<u>\$ (50,337,230)</u>		<u>(2.49461)</u>
12	2011 RTO-NE 12-CP RNS Load:				20,178,343		kW						
(a) Amounts include adjustments related to the FERC Audits.													

(a) Amounts include adjustments related to the FERC Audits.

Attachment 5

**Schedule 1 Rates Effective June 1, 2012 – May 31, 2013
Based on 2011 Data**

SUMMARY

ISO NE Transmission, Markets & Services Tariff OATT Regional Schedule 1 - Scheduling System Control and Dispatch Service Rate Effective June 1, 2012 - May 31, 2013 (Reflecting 2011 Schedule 1 Costs)

1 Total of FERC account 561-561.4 (exclude ME, REMVEC, CONVEX /ESCC costs)	\$ 15,268,104	1
2 Less ISO & OATT Sch 1 costs included in above accounts	1,587,252	2
3 Sub-total (1-2)	13,680,852	3
4 Amount allocated to transmission function	13,680,852	4
5 Transmission related S&D costs from SCADA or other systems	6,405,380	5
6 Sub-total (4+5)	20,086,232	6
7 PTF allocation factors (see page 2 for details)	78.4864%	7
8 Sub-total after applying PTF allocation factors (from page 2)	15,764,958	8
9 Maine LCC costs	4,464,323	9
10 REMVEC II costs	1,391,642	10
11 CONVEX costs	15,957,486	11
12 Sub-total (9+10+11)	21,813,451	12
13 100% allocated to transmission function	21,813,451	13
14 Revenues credited for short-term Transmission Service	(1,458,166)	14
15 Total transmission related system & dispatch revenue requirement (8+13+14)	36,120,242	15
16 12 month CP LOAD (KW) as defined in section 46.1 of the ISO-NE Tariff	20,178,343	16
17 Long Term Firm PTP Capacity (KW)	-	17
18 Scheduling System Control and Dispatch Service Rate (\$/KW-YR): (15/(16+17))	\$ 1.79005	18

DETAIL

ISO NE Transmission, Markets & Services Tariff																				
OATT Regional Schedule 1 - Scheduling System Control and Dispatch Service Rate																				
Effective June 1, 2012 - May 31, 2013																				
(Reflecting 2011 Schedule 1 Costs)																				
				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15		16
				Total of FERC acct 561 - 561.4 (exclude ME, REMVEC, CONVEX /ESCC costs)	Less Reg Sch 1 & ISO costs included in Column 1 accounts	Sub-total (1-2)	100% allocated to transmission function	Transmission related S&D costs from SCADA or other Local Control Centers	Sub-total (4+5)	PTF Allocation Factor	Sub-total (6x7)	Maine LCC - PTF RELATED SCH 1 REV REQ'TS.	REMVEC II Costs	CONVEX/ESCC Costs	Sub-total (9+10+11)	100% allocated to transmission function	Revenues credited for short-term transmission service must be negative	TOTAL (8+13+14)		SCHEDULE 1 Revenue Allocation %
	Customer #	DUNS	DUNS Name																	
1	3	00-695-1552	NSTAR					6,405,380	6,405,380	85.5662%	5,480,840				-	-	(273,889)	5,206,951	1	14.41560%
2	2	00-694-9002	Bangor Hydro Transmission	508,341		508,341	508,341		508,341	68.7136%	349,299	281,424			281,424	281,424	(23,300)	607,423	2	1.68167%
3	6	00-694-8954	Central Maine Power Transmission	-		-	-	-	-		-	4,009,341			4,009,341	4,009,341	(178,299)	3,831,042	3	10.60636%
4	6	06-099-4258	Maine Electric Power Company	65,966		65,966	65,966		65,966	100.0000%	65,966	173,558			173,558	173,558	(7,416)	232,108	4	0.64260%
5	1	83-729-7852	Ashburnham, Town of			-	-		-		-		542		542	542	(22)	520	5	0.00144%
6	4	06-991-6021	Boylston, Town of			-	-		-		-		508		508	508	(20)	488	6	0.00135%
7	5	17-057-1897	Braintree, Town of			-	-		-		-		8,284		8,284	8,284	(344)	7,940	7	0.02198%
8	9	15-596-9157	Danvers, Town of			-	-		-		-		6,713		6,713	6,713	(270)	6,443	8	0.01784%
9	38	00-695-4317	Unitil Fitchburg Gas & Electric Company Inc	120,906	113,980	6,926	6,926		6,926	21.0531%	1,458		9,681		9,681	9,681	(598)	10,540	9	0.02918%
10	39	15-596-9983	Georgetown, Town of			-	-		-		-		713		713	713	(29)	684	10	0.00189%
11	40	15-601-8301	Groton, Town of			-	-		-		-		957		957	957	(39)	918	11	0.00254%
12	42	14-703-0704	Hingham, Town of			-	-		-		-		3,129		3,129	3,129	(126)	3,003	12	0.00831%
13	43	87-808-0563	Holden, Town of			-	-		-		-		1,928		1,928	1,928	(78)	1,850	13	0.00512%
14	45	10-775-5126	Hudson, Town of			-	-		-		-		5,943		5,943	5,943	(240)	5,703	14	0.01579%
15	72	13-661-7156	Hull, Town of			-	-		-		-		887		887	887	(36)	851	15	0.00236%
16	73	15-586-9563	Ipswich, Town Of			-	-		-		-		1,994		1,994	1,994	(80)	1,914	16	0.00530%
17	75	79-432-5019	Littleton, Town of			-	-		-		-		4,368		4,368	4,368	(176)	4,192	17	0.01161%
18	77	95-690-6051	Mansfield, Town of			-	-		-		-		4,366		4,366	4,366	(176)	4,190	18	0.01160%
19	78	15-598-9544	Marblehead, Town of			-	-		-		-		2,120		2,120	2,120	(86)	2,034	19	0.00563%
20	79	15-597-6665	Middleborough, Town of			-	-		-		-		2,627		2,627	2,627	(106)	2,521	20	0.00698%
21	80	18-675-8231	Middleton, Town of			-	-		-		-		1,521		1,521	1,521	(62)	1,459	21	0.00404%
22	111	10-798-9241	North Attleboro Electric			-	-		-		-		4,372		4,372	4,372	(176)	4,196	22	0.01162%
23	116	06-984-9461	Pascoag Utility District			-	-		-		-		464		464	464	(19)	445	23	0.00123%
24	117	15-582-5391	Paxton, Town of			-	-		-		-		407		407	407	(16)	391	24	0.00108%
25	144	10-371-6353	Peabody, City of			-	-		-		-		8,829		8,829	8,829	(356)	8,473	25	0.02346%
26	145	96-152-2786	Princeton, Town of			-	-		-		-		293		293	293	(12)	281	26	0.00078%
27	148	86-703-4654	Reading, Town of			-	-		-		-		8,714		8,714	8,714	(351)	8,363	27	0.02315%
28	146	11-885-5188	Rowley, Town of			-	-		-		-		588		588	588	(23)	565	28	0.00156%
29	149	78-451-8870	Shrewsbury, Town of			-	-		-		-		5,879		5,879	5,879	(237)	5,642	29	0.01562%
30	152	15-586-0620	Sterling, Town of			-	-		-		-		761		761	761	(30)	731	30	0.00202%
31	153	04-661-6033	Taunton Municipal Lighting Plant			-	-		-		-		11,068		11,068	11,068	(446)	10,622	31	0.02941%
32	180	02-619-2302	Templeton, Town of			-	-		-		-		1,666		1,666	1,666	(67)	1,599	32	0.00443%
33	183	15-415-7622	Wakefield Municipal Gas & Light Department			-	-		-		-		3,503		3,503	3,503	(141)	3,362	33	0.00931%
34	186	12-787-0350	West Boylston, Town of Inc			-	-		-		-		1,245		1,245	1,245	(50)	1,195	34	0.00331%
35	81	00-695-2881	New England Electric Transmission	9,662,945		9,662,945	9,662,945		9,662,945	73.2131%	7,074,542		1,287,572		1,287,572	1,287,572	(322,669)	8,039,445	35	22.25745%
36			Connecticut Light & Power	86,853		86,853	86,853		86,853	87.6953%	76,166			14,877,142	14,877,142	14,877,142	(518,930)	14,434,378	36	39.96202%
37			Public Service of New Hampshire	196,368		196,368	196,368		196,368	92.5167%	181,673			1,071,412	1,071,412	1,071,412	(50,674)	1,202,411	37	3.32891%
38			Western Massachusetts Electric Co.	17,257		17,257	17,257		17,257	87.3466%	15,073		8,932	8,932	8,932	8,932	(2,078)	21,927	38	0.06071%
39	112	95-910-8929	Northeast Utilities Transmission	300,478	-	300,478	300,478		300,478		272,912			15,957,486	15,957,486	15,957,486	(571,682)	15,658,716	39	43.35164%
40	181	00-691-7967	United Illuminating Company, The	1,506,653	1,473,272	33,381	33,381		33,381	87.9494%	29,358				-	-	(1,055)	28,303	40	0.07836%
41	50853	78-039-9163	Vermont Transco, LLC	3,102,815		3,102,815	3,102,815		3,102,815	80.2685%	2,490,583				-	-	(75,444)	2,415,139	41	6.68639%
42			TOTALS	\$ 15,268,104	\$ 1,587,252	\$ 13,680,852	\$ 13,680,852	\$ 6,405,380	\$ 20,086,232	78.4864%	\$ 15,764,958	\$ 4,464,323	\$ 1,391,642	\$ 15,957,486	\$ 21,813,451	\$ 21,813,451	\$ (1,458,166)	\$ 36,120,242	42	100.00%

ISO NE Transmission, Markets & Services Tariff		
OATT Regional Schedule 1 - Scheduling System Control and Dispatch Service Rate		
Effective June 1, 2012 - May 31, 2013		
(Reflecting 2011 Schedule 1 Costs)		
COMPANY		SCHEDULE 1 DISTRIBUTION %
Ashburham		0.00144%
Bangor Hydro		1.68167%
NSTAR		14.41560%
Boylston		0.00135%
Braintree		0.02198%
Central Maine Power		10.60636%
MEPCO		0.64260%
Danvers		0.01784%
Fitchburg Gas & Electric		0.02918%
Georgetown		0.00189%
Groton, MA		0.00254%
Hingham		0.00831%
Holden		0.00512%
Hudson		0.01579%
Hull		0.00236%
Ipswich		0.00530%
Littleton, MA		0.01161%
Mansfield		0.01160%
Marblehead		0.00563%
Middleboro		0.00698%
Middleton		0.00404%
N.Attleboro		0.01162%
National Grid		22.25745%
Northeast Utilities		43.35164%
Pascoag		0.00123%
Paxton		0.00108%
Peabody		0.02346%
Princeton		0.00078%
Reading		0.02315%
Rowley		0.00156%
Shrewsbury		0.01562%
Sterling		0.00202%
Taunton		0.02941%
Templeton		0.00443%
United Illuminating		0.07836%
VTransco		6.68639%
W. Boylston		0.00331%
Wakefield		0.00931%
	TOTAL =	100.00%

**PTOs' Annual Revenue Requirement Calculations
Pursuant to Schedule 1 and based on 2011 Data**

**CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/11**

Sheet: Input Panel

ISO-NE Tariff Billing
System Control and Dispatch Service Local Control Center Revenue Requirements
per Appendix B of the Rule Implementing the Schedule 1 Rate Surcharge

 Shading denotes an input

Effective:	6/1/2012
Submitted on:	5/7/2012
Revenue Requirements for (year):	Unadjusted Test Year ended 12/31/11
Customer:	Central Maine Power Company
Customer's NABs Number:	06
Name of Participant responsible for customer's billing:	Central Maine Power Company
DUNs number of Participant responsible for customer's billing:	006948954

		2011 Revenue Requirements
Total of Appendix A - Sections A through I	=	7,262,610 (a)
Total of Appendix A - Section J - Support Revenue		478,982 (b)
Total Annual Revenue Requirement		\$ 6,783,628 (c)=(a)-(b)
Transmission Related Revenue Requirement		\$ 6,783,628 (d)= (c)* Satellite Wages & Salaries Allocation Factor
PTF Related Revenue Requirement		\$ 4,009,341 (e)= (d)* Satellite PTF Allocation Factor

**CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/11**

Worksheet 1 of 11

Line No.		Formula Reference		Reference
II. INVESTMENT BASE				
1	Local Control Center Plant	II (A)(1)(a)	\$ 21,840,009	Worksheet 3, line 1 column 3
3	Plant Held For Future Use	II (A)(1)(b)	2,441	Worksheet 3, line 3 column 3
4	Total Plant (Lines 1+2+3)		21,842,450	
5	Accumulated Depreciation	II (A)(1)(c)	13,234,045	Worksheet 3, line 5 column 3
6	Accumulated Deferred Income Taxes	II (A)(1)(d)	4,506,668	Worksheet 3, line 10 column 3
7	Loss On Reacquired Debt	II (A)(1)(e)	35,933	Worksheet 3, line 12 column 3
8	Other Regulatory Assets	II (A)(1)(f)	2,994,897	Worksheet 3, line 17 column 3
9	Net Investment (Line 4-5-6+7+8)		7,132,567	
11	Prepayments	II (A)(1)(g)	34,271	Worksheet 3, line 19 column 3
12	Materials & Supplies	II (A)(1)(h)	93,459	Worksheet 3, line 21 column 3
13	Cash Working Capital	II (A)(1)(i)	672,953	Worksheet 3, line 28 column 3
14	Total Investment Base (Line 9+11+12+13)		\$ 7,933,250	
II. REVENUE REQUIREMENTS				
15	Investment Return and Income Taxes	II (A)	\$ 1,182,036	Worksheet 2, line 44
16	Depreciation Expense	II (B)	556,734	Worksheet 4, line 1 column 3
17	Amortization of Loss on Reacquired Debt	II (C)	8,276	Worksheet 4, line 3 column 3
18	Investment Tax Credit	II (D)	(8,318)	Worksheet 4, line 5 column 3
19	Municipal Taxes	II (E)	140,258	Worksheet 4, line 7 column 3
20	Payroll Taxes	II (F)	0	Worksheet 4, line 9 column 3
21	Operation & Maintenance Expense	II (G)	3,585,675	Worksheet 4, line 16 column 3
22	Administrative & General Expense	II (H)	1,797,949	Worksheet 4, line 22 column 3
24	Transmission Support Revenue	II (I)	(478,982)	Worksheet 11, line 6
30	Total Revenue Requirements (Line 15 thru 29)		\$ 6,783,628	
	Local Control Center Wages and Salaries Allocation Factor		100.00%	Worksheet 5, line 20
	Transmission Related Revenue Requirement		\$ 6,783,628	
	Local Control Center PTF Allocation Factor		59.10%	Worksheet 5, line 29
	PTF Transmission Related Revenue Requirement		\$ 4,009,342	

**CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/11**

Worksheet 2 of 11

	CAPITALIZATION 12/31/11	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION	
1 LONG-TERM DEBT	\$ 587,700,000	34.226%	5.970%	2.043%		Worksheet 9, line 5
2 PREFERRED STOCK	2,660,500	0.155%	5.062%	0.008%	0.008%	Worksheet 9, line 6
3 COMMON EQUITY	<u>1,126,741,425</u>	<u>65.619%</u>	11.640%	<u>7.638%</u>	<u>7.638%</u>	Worksheet 9, line 7
4						
5 TOTAL INVESTMENT RETURN	\$ <u>1,717,101,925</u>	<u>100.00%</u>		<u>9.689%</u>	<u>7.646%</u>	
6						
7 New Inv Adder Calc.		65.619%		0.000%	0.000%	0.000% including FIT&SIT
8						
9 Cost of Capital Rate=						
10						
11 (a) Weighted Cost of Capital	=	<u>0.0969</u>				
12						
13						
14 (b) Federal Income Tax	=	$\left(\frac{\text{R.O.E.} + \left(\frac{\text{Satellite Inv. Tax Credit - w/s 1, line 18} + \text{Eq. AFUDC of Deprec. Exp.} / \text{Satellite Inv. Base}}{1} \right)}{1} \right) \times \frac{\text{Federal Income Tax Rate}}{\text{Federal Income Tax Rate}}$				
15						
16						
17	=	$\left(\frac{0.0765 + \left(\frac{(8,318) + 1,441}{7,933,250} \right)}{1} \right) \times 0.35$				
18						
19						
20	=	<u>0.0407040</u>				
21						
22						
23 (c) State Income Tax	=	$\left(\frac{\text{R.O.E.} + \left(\frac{\text{Satellite Inv. Tax Credit} + \text{Eq. AFUDC of Deprec. Exp.}}{1} \right)}{1} \right) \times \frac{\text{Federal Income Tax Rate}}{\text{State Income Tax Rate}} \times \text{State Income Tax Rate}$				
24						
25						
26	=	$\left(\frac{0.0765 + \left(\frac{(8,318) + 1,441}{7,933,250} \right)}{1} \right) \times 0.0407040$				
27						
28						
29	=	<u>0.0114037</u>				
30						
31						
32						
33 (a)+(b)+(c) Cost of Capital Rate	=	<u>0.1489977</u>				
34						
35						
36						
37						
38						
39						
40 INVESTMENT BASE	\$	7,933,250	0			
41						
42 x Cost of Capital Rate		0.1489977	0.0000000			
43						
44 = Investment Return and Income Taxes		<u>1,182,036</u>	<u>0</u>	<u>1,182,036</u>	w/s 1 line 15	

Investment Base Calculation for Incremental Return		
Post 2003 Inv	= \$	- ws 6
Deprec Res		- ws 7
ADITs		tax dept
Investment Base	\$	-

**CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/11**

Worksheet 3 of 11

Line No.	(1) Total	(2) Allocation Factors	(3) = (1)*(2) Local Control Center Allocated	Schedule 1 Rate Worksheet or FERC Form 1 Reference for col (1) or (3)
1	<u>Local Control Center Plant</u>	21,840,009	21,840,009	Worksheet 6, c.(a) l.17
2				
3	<u>Local Control Center Plant Held for Future Use</u>	209,797	1.1635% (a) 2,441	Worksheet 11, line 1
4				
5	<u>Local Control Center Accumulated Depreciation</u>	(13,234,045)	(13,234,045)	Worksheet 6, c.(b) l.17
6				
7	<u>Local Control Center Accumulated Deferred Taxes</u>			
8	Accumulated Deferred Taxes (281-283)	(557,533,074)	1.1635% (a) (6,486,897)	Worksheet 11, line 3
9	Accumulated Deferred Taxes (190)	170,195,885	1.1635% (a) 1,980,229	Worksheet 11, line 2
10	Total (line 8+9)	(387,337,189)	(4,506,668)	
11				
12	<u>Unamortized loss on Reacquired Debt</u>	3,088,334	1.1635% (a) 35,933	Page 111.81c
13				
14	<u>Other Regulatory Assets</u>			
15	FAS 106	9,528,029	4.5588% (b) 434,364	Page 232.1, lines 18f
16	FAS 109	220,071,636	1.1635% (a) 2,560,533	Page 232.1, line 27f - Page 278 34f
17	Total (line 12+13)	229,599,665	2,994,897	
18				
19	<u>Prepayments</u>	2,945,473	1.1635% (a) 34,271	Page 111.57c
20				
21	<u>Total Materials and Supplies</u>	8,032,573	1.1635% (a) 93,459	Worksheet 11, line 4
22				
23	<u>Cash Working Capital</u>			
24	Operation & Maintenance Expense		3,585,675	Worksheet 1, Line 21
25	Administrative & General Expense		1,797,949	Worksheet 1, Line 22
26	Subtotal (line 18+19+20)		5,383,624	
27			0.125	x 45 / 360
28	Total (line 21 * line 22)		672,953	

(a) Worksheet 5, line 37
(b) Worksheet 5, line 11

**CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/11**

Worksheet 4 of 11

Line No.		(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Local Control Center Allocated	Worksheet or FERC Form 1 Reference for col (1)
1	<u>Local Control Center Depreciation Expense</u>	556,734		556,734	Worksheet 6, c.d, l. 17
2					
3	<u>Amortization of Loss on Reacquired Debt</u>	711,263	1.1635% (b)	8,276	Page 117.64c
4					
5	<u>Amortization of Investment Tax Credits</u>	(714,950)	1.1635% (b)	(8,318)	Page 266.8.f
6					
7	<u>Local Control Center Property Taxes</u>	12,054,848	1.1635% (b)	140,258	w/s 11, line 5
8					
9	<u>Payroll Taxes</u> (c)	-	4.5588% (a)	-	
10					
11	<u>Operation and Maintenance</u>				
12	System Control and Load Dispatch - #556	0			Page 321.77b
13	Load Dispatching - #561 - 561.4	3,585,675			Page 321.84b thru 88b & ws 7
14	Load Dispatching - #581	0			581 excluded from Transmission
15	Less expenses incurred under ISO Tariff	-			ISO Tariff costs charged to 565
16	O&M - line 12+13+14-15	<u>3,585,675</u>		<u>3,585,675</u>	
17					
18	<u>Administrative and General</u>				
19	A & G subject to Wage & Salaries Allocation Factor	39,364,926	4.5588% (a)	1,794,568	Worksheet 8, line 30
20	A & G subject to Plant Allocation Factor	290,630	1.1635% (b)	3,381	Worksheet 8, line 33
21	A & G directly assigned to Local Control Center	-	100.0000%	-	Worksheet 8, lines 15& 18
22	A&G (lines 19+20+21)	<u>39,655,556</u>		<u>1,797,949</u>	

(a) Worksheet 5, line 11

(b) Worksheet 5, line 37

(c) Payroll taxes - FERC Form 1, page 263 lines 3,5&9 col i&l are recorded in acc't 184 and then cleared and properly functionalized to the appropriate accounts.

**CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/11**

Worksheet 5 of 11

Sch. 1 Rate
Worksheet or
FERC Form 1
Reference

Line
No.

1			
2	<u>Wages and Salaries Allocation Factor</u>	<u>2011</u>	
3			
4	Total Local Control Center Direct Wages and Salaries	1,812,200	worksheet 7, c.(d).l.5
5			
6	Total Wages and Salaries	44,543,516	Page 354.28b
7	Administrative and General Wages and Salaries	4,791,627	Page 354.27b
8	Affiliated Company Wages and Salaries less A&G	-	
9	Total Wages and Salaries net of A&G (line 6-7)	39,751,889	
10			
11	Percent Allocation (lines 4 / 9)	<u>4.5588%</u>	
12			
13			
14	<u>Local Control Center Wages and Salaries Allocation Factor</u>		
15			
16	Total Transmission Local Control Center Direct Wages and Salaries	1,812,200	worksheet 7, c.(d).l.2
17			
18	Total Local Control Center Direct Wages and Salaries	1,812,200	worksheet 5, l.4
19			
20	Percent Allocation (lines 16/18)	<u>100.0000%</u>	
21			
22			
23	<u>Local Control Center PTF Allocation Factor</u>		
24			
25	Total Local Control Center PTF Direct Wages and Salaries	1,071,069	worksheet 7, c.(e).l.2
26			
27	Total Transmission Local Control Center Direct Wages and Salaries	1,812,200	worksheet 5, l.4
28			
29	Percent Allocation (line 25/27)	<u>59.1032%</u>	
30			
31			
32	<u>Local Control Center Plant Allocation Factor</u>		
33			
34	Total Investment in Local Control Center Plant	21,840,009	worksheet 6, c.(a).l.17
35	Total Plant in Service	1,877,082,238	Page 207.104g
36			
37	Percent Allocation (lines 34/35)	<u>1.1635%</u>	

**CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/11**

Worksheet 6 of 11

/-----12/31/11-----/				
<u>PROPERTY DESCRIPTION</u>	<u>COST</u>	<u>RESERVE</u>	<u>2011 DEPRECIATION</u>	<u>ref</u>
	(a)	(b)	©	
1 FURNITURE & EQUIPMENT	2,700,589	246,358	88,409	Fixed Assets
2 STRUCTURE COSTS & MAP BOARDS	4,468,109	1,702,845	100,676	Fixed Assets
3 UPS	284,858	158,675	10,550	Fixed Assets
4 COMMUNICATION EQUIPMENT	815,265	541,468	59,677	Fixed Assets
5 EMS HARDWARE	1,834,871	1,495,973	203,854	Fixed Assets
6				Fixed Assets
7				Fixed Assets
8 EMS SOFTWARE	7,900,188	7,900,188	-	Fixed Assets
9 S/S & GEN STA. RTUs & SCADA	3,836,129	1,188,538	93,566	Fixed Assets
10				Fixed Assets
11				Fixed Assets
12				Fixed Assets
13				
14				
15				
16				
17 TOTALS	21,840,009	13,234,045	556,734	

**CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/11**

Worksheet 7 of 11

FERC ACCT			TOTAL EXPENSE (a)	P/R OH & OTHER EXPENSES (b)	SALARIES & WAGES ©	PTF SALARIES & WAGES (d)	NON-PTF SALARIES & WAGES (e)
1	561.1 Load Dispatch-Reliability	Page 321.85b	\$ 957,535	\$ 517,343	\$ 440,192	260,167	180,024
2	561.2 Load Dispatch-Monitor & Operate Transmission System	Page 321.86b	2,614,634	1,242,626	1,372,008	810,901	561,107
	561.3 Load Dispatch-Transmisssion Service & Scheduling	Page 321.87b	13,506	13,506	-	-	-
3	561.4 Scheduling, System Control & Dispatch Services	Page 321.88b	-	-	-	-	-
4							
5	TOTAL		\$ 3,585,675	\$ 1,773,475	\$ 1,812,200	1,071,069	741,131
6							

**CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/11**

Worksheet 8 of 11

Acc't	Description	Amount	
1	920 Administrative and General Salaries	6,838,260	
2	921 Office Supplies and Expenses	2,612,247	
3	922 Less Administrative Expenses Transferred - Credit	(490,590)	
4	923 Outside Services Employed	22,771,469	
5	924 Property Insurance	290,630	
6	925 Injuries and Damages	2,312,523	
7	926 Employee Pensions and Benefits	(7,064,577)	
8	928 Regulatory Commissions Expense	4,728,904	
9	930.1 General Advertising	1,628,798	
10	930.2 Miscellaneous General Expense	1,582,968	
11	931 Rents	921,706	
12	935 Maintenance of General Plant	1,785,722	
13	Total Admin & Gen'l Exp.	37,918,060	Page 323.197b
14	FERC assessments - Transmission (directly assigned)	676,625	
15	FERC assessments - Satellite (directly assigned)	-	to worksheet 4, line 21
16	FERC assessments - subject to plant allocation factor	-	FF1 page 350.d
17	TOTAL FERC ASSESSMENTS (14+15)	676,625	FF1 page 350.d
18	State assessments - Satellite (directly assigned)	-	to worksheet 4, line 21
19	Total State Assessments	4,052,279	FF1 page 350.d
	928 Total Regulatory Commissions Expense: (16+18) & from line 8	4,728,904	FF1 page 46.d
20			
21	General Advertising - Transmission related	-	
22	Non-Satellite related General Advertising Exp.	1,628,798	
	930.1 Total General Advertising Exp. (line 9)	1,628,798	Page 323 191.b
23	Summary of Schedule 1 Treatment of A&G		
24	Total A&G (line 13)	37,918,060	
25	924 less Property Insurance (line 5)	290,630	
26	928 less Regulatory Commissions Exp. (line 19)	4,728,904	
27	930.1 less Non-Trans. General Advertising Exp. (line 9)	1,628,798	
28	920-935 less EPRI Expenses	-	
29	926 less pension credit directly assigned to T&D	(8,095,198)	MPUC Docket Nos. 2007-215/2008-111
30	A&G subject to Wages and Salaries Allocation Factor:	39,364,926	to ws 4, line 19, col. 1
31	Property Insurance (line 5)	290,630	
32	Regulatory Commissions Exp. - FERC assessments (line 15)	-	
33	Total A&G subject to Plant Allocation Factor	290,630	to ws 4, line 20, col. 1

**CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/11**

Worksheet 9 of 11

		CAPITALIZATION 12/31/11	CAPITALIZATION RATIOS	COST OF CAPITAL	ANNUAL INTEREST	COST OF CAPITAL	EQUITY PORTION
1	MED-TERM NOTES	page 123.5	418,200,000	24.355%	6.671%	27,898,122	
2	POLLUTION CONTROL NOTES	page 123.5	19,500,000	1.136%	5.594%	1,090,830	
3	FAME	page 123.5	-	0.000%	0.000%	-	
4	MORTGAGE BONDS	page 123.5	150,000,000	8.736%	4.200%	6,300,000	
5	TOTAL LONG-TERM DEBT		587,700,000	34.227%	5.970%	35,288,952	2.043%
6	PREFERRED STOCK	page 123.6 and page 112.3d	2,660,500	0.155%	5.062%		0.008%
7	COMMON EQUITY	page 112.16d less line 3d	1,126,741,425	65.619%	11.640%		7.638%
8							
9	TOTAL INVESTMENT RETURN		1,717,101,925	100.00%		9.689%	7.646%
10							
11							
12	Capitalization excludes short term debt(i.e. Revolving Credit Agreement)						
13							

**CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/11**

Source: USS

Worksheet 10 of 11

	<u>Vintage</u>	<u>Cost</u>	<u>AFUDC</u>	<u>% of Total</u>
	<u>Transmission Assets:</u>			
1	1953-1970	no afudc data available		
2	1971	16,993,929	210,398	1.24%
3	1972	1,354,874	-	0.00%
4	1973	2,530,521	21,837	0.86%
5	1974	3,929,745	200	0.01%
6	1975	4,626,387	38,383	0.83%
7	1976	6,559,880	76,909	1.17%
8	1977	5,885,933	86,351	1.47%
9	1978	17,338,606	444,301	2.56%
10	1979	4,115,534	14,481	0.35%
11	1980	7,717,864	28,543	0.37%
12	1981	3,806,576	45,143	1.19%
13	1982	3,336,346	16,508	0.49%
14	1983	5,462,226	107,741	1.97%
15	1984	6,543,576	188,256	2.88%
16	1985	2,153,012	13,995	0.65%
17	1986	4,063,381	72,616	1.79%
18	1987	6,308,982	70,120	1.11%
19	1988	8,616,426	96,074	1.12%
20	1989	8,190,862	92,568	1.13%
21	1990	18,606,637	300,769	1.62%
22	1991	6,804,433	68,667	1.01%
23	1992	10,041,560	178,995	1.78%
24	1993	5,637,279	121,080	2.15%
25	1994	3,480,922	26,059	0.75%
26	1995	3,820,449	32,298	0.85%
27	1996	2,681,701	20,928	0.78%
28	1997	1,790,063	23,501	1.31%
29	1998	1,477,852	4,185	0.28%
30	1999	1,810,857	10,989	0.61%
31	2000	26,037,439	264,455	1.02%
32	2001	8,983,040	92,232	1.03%
33	2002	8,622,712	117,487	1.36%
34	2003	2,701,882	(16,453)	-0.61%
35	2004	13,379,541	151,747	1.13%
36	2005	10,790,340	187,716	1.74%
37	2006	14,151,218	57,062	0.40%
38	2007	41,386,528	247,340	0.60%
39	2008	84,332,796	3,500,923	4.15%
40	2009	44,549,845	355,246	0.80%
41	2010	20,636,193	558,551	2.71%
42	2011	87,885,769	374,354	0.43%
43	totals	539,143,716	8,302,555	1.54%
44				
45	Transmission Plant related Depreciation Expense:		\$ 93,566	From Worksheet 6, line 11
46				
47	AFUDC Adjustment		1,441	To Worksheet 2

Note: No AFUDC was capitalized related to general plant investments, as they were purchased and not constructed.

**CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/11**

Worksheet 11 of 11

Line #	Description	FERC FORM 1 REF.	FERC FORM I Bal.	Less Amounts Assigned to Transmission	Amount for Schedule 1	Sch. 1 w/s ref
1	Plant Held for future use	Page 200, line 10c	3,606,109	3,396,312	209,797	w/s 3, line 3
	Accumulated Deferred Income Taxes:					
2	190	Page 234.8c	211,606,486	41,410,601	170,195,885	w/s 3, line 9
	282	Page 113.63c	(378,066,204)	81,428,346	(296,637,858)	
	283	Page 113.64c	(308,257,699)	47,362,483	(260,895,216)	
3	subtotal 281-283		(686,323,903)	128,790,829	(557,533,074)	w/s 3, line 8
4	Materials & Supplies	Page 227.11c	11,853,196	3,820,623	8,032,573	w/s 3, line 21
	Total Real and Personal Propoerty 408.1	Page 263.14 i	20,684,621	6,379,370	14,305,250	
	Less Sales & Use Taxes		2,250,403	-	2,250,403	
5	Property Taxes		18,434,218	6,379,370	12,054,848	w/s 4, line 7

Local Control Center Support Revenues & Rents:

MEPCO	\$ (173,558)	454099	PE78946	
BHE	(281,424)	454010	PE78946	
Microwave	(24,000)	454000	PE78947	
6 Total LCC Revenue	<u>\$ (478,982)</u>			w/s 1 line 24

NSTAR Electric Company
Annual Schedule 1 Revenue Requirements - Dispatch Center
Cost Year: 2011
Sheet 1

	(a)	(b)	(c)	(d)
Line	Description	Tariff Section	Amount	Reference
1	Dispatch Center Investment Base	A.1		
2	Dispatch Center Plant	A.1.a	\$ 11,270,751	Sheet 3, Line 1(f)
3	Dispatch Center Related General Plant	A.1.b	2,821,500	Sheet 3, Line 2(f)
4	Dispatch Center Plant Held for Future Use	A.1.c	-	Sheet 3, Line 3(f)
5	Total Plant		\$ 14,092,251	Sum Lines 2 thru 4
6	Dispatch Center Related Depreciation Reserve	A.1.d	(4,736,608)	Sheet 3, Line 7(f)
7	Dispatch Center Related Accumulated Deferred Taxes	A.1.e	(3,414,769)	Sheet 3, Line 13(f)
8	Total Net Plant		\$ 5,940,874	Sum Lines 5 thru 7
9	Other Regulatory Assets	A.1.f	133,336	Sheet 3, Line 18(f)
10	Dispatch Center Prepayments	A.1.g	87,486	Sheet 3, Line 20(f)
11	Dispatch Center Materials & Supplies	A.1.h	7,853	Sheet 3, Line 21(f)
12	Dispatch Center Related Cash Working Capital	A.1.i	585,118	Sheet 3, Line 25(f)
13	Total Dispatch Center Investment Base		\$ 6,754,667	Sum Lines 8 thru 12
14	Revenue Requirements			
15	Investment Return and Income Taxes	A.2	\$ 899,256	Sheet 2, Line 38(c)
16	Dispatch Center Depreciation Expense	B	411,982	Sheet 4, Line 4(f)
17	Dispatch Center Related Amortization of Investment Tax Credits	C	(3,443)	Sheet 4, Line 5(f)
18	Dispatch Center Related Municipal Tax Expense	D	250,204	Sheet 4, Line 6(f)
19	Dispatch Center Related Payroll Tax Expense	E	166,435	Sheet 4, Line 26(f)
20	Dispatch Center Operation & Maintenance Expense	F	2,488,437	Sheet 4, Line 13(f)
21	Dispatch Center Related Administrative and General Expenses	G	2,192,510	Sheet 4, Line 25(f)
22	Revenues Received from ISO		-	Sheet 5, Line 3(f)
23	Total Revenue Requirements		\$ 6,405,380	Sum Lines 15 thru 22
24	PTF Transmission Plant Allocator		85.5662%	RNS Sheet 6
25	PTF Revenue Requirement for SCADA		\$ 5,480,840	Line 23 * Line 24

NSTAR Electric Company
Investment Return and Income Taxes
Cost Year: 2011
Sheet 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line	Description	Tariff Section	Balance	Capitalization Ratio	Cost*	Weighted Cost	Equity Cost	Reference
1	Weighted Cost of Capital	A.2.a						
2	Long Term Debt	A.2.a.i	1,595,344,024	41.2267%	5.38%	2.2189%		Page 112.24c
3	Preferred Stock	A.2.a.ii	43,000,000	1.1112%	4.56%	0.0507%	0.0507%	Page 112.3c
4	Common Equity	A.2.a.iii	2,231,342,641	57.6621%	11.64%	6.7119%	6.7119%	Page 112.16c (less Line 3)
5	Total		3,869,686,665	100.0000%		8.9814%	6.7625%	Sum Lines 2 thru 4
6	Total Investment Base		6,754,667					Sheet 1, Line 13(c)
7	Weighted Cost of Capital		8.9814%					Line 5, Col (f)
8	Total Return on Investment		\$ 606,663					Line 6 * Line 7
9	Federal Income Tax	A.2.b						
10	A = Equity Cost		6.7625%					Line 5, Col (g)
11	B = Transmission Amortization of ITC		(3,443)					Sheet 4, Line 5(f)
12	C = Equity AFUDC		-					
13	Total B + C		(3,443)					Line 11 + Line 12
14	D = Investment Base		6,754,667					Line 6
15	(B + C) / D		-0.0510%					Line 13 / Line 14
16	(A + [(C + B) / D])		6.7115%					Line 10 + Line 15
17	FT = Federal Income Tax Rate		35.0000%					
18	1 - FT		65.0000%					1 - Line 17
19	Federal Tax Factor		3.6139%					Line 16 * Line 17 / Line 18
20	Total Federal Income Taxes		\$ 244,108					Line 14 * Line 19
21	State Income Tax	A.2.c						
22	A = Equity Cost		6.7625%					Line 5, Col (g)
23	B = Transmission Amortization of ITC		(3,443)					Sheet 4, Line 5(f)
24	C = Equity AFUDC		-					
25	Total B + C		(3,443)					Line 23 + Line 24
26	D = Investment Base		6,754,667					Line 6
27	(B + C) / D		-0.0510%					Line 25 / Line 26
28	(A + [(C + B) / D])		6.7115%					Line 22 + Line 27
29	ST = State Income Tax Rate		6.5000%					
30	1 - ST		93.5000%					1 - Line 29
31	Federal Tax Factor		3.6139%					Line 22
32	State Tax Factor		0.7178%					(Line 28 + Line 31) * Line 29 / Line 30
33	Total State Income Taxes		\$ 48,486					Line 26 * Line 32
34	Investment Return and Income Taxes	A.2						
35	Return on Investment		606,663					Line 8
36	Federal Income Taxes		244,108					Line 20
37	State Income Taxes		48,486					Line 33
38	Total Investment Return and Income Taxes		\$ 899,256					Sum Lines 35 thru 37
39	Value of 50BP ROE Adder							
40	ROE Adder		0.5000%					Per Tariff
41	Equity Ratio		57.6621%					Line 4, Col (d)
42	Effective Adder		0.2883%					Line 40 * Line 41
43	Tax Gross-up		0.1861%					Line 19 * .645413
44	Adder plus Gross-up		0.4744%					Line 42 + Line 43
45	Rate Base		\$ 6,754,667					Line 6
46	Earned Adder		\$ 32,043					Line 44 * Line 45
47	PTF Ratio		85.57%					RNS Sheet 6
48	PTF Related Adder		\$ 27,418					Line 46 * Line 47

NSTAR Electric Company
Dispatch Center Investment Base
Cost Year: 2011
Sheet 3

Line	(a) Description	(b) Tariff Section	(c) Total	(d) Allocator	(e) Allocation Factor	(f) Dispatch Center Allocated	(g) Reference
1	Dispatch Center Plant	A.1.a	11,270,751	Direct	100.0000%	11,270,751	Sheet 6, Line 12(c)
2	Dispatch Center Related General Plant	A.1.b	181,870,260	W&S	1.5514%	2,821,500	FF1 207.99g
3	Dispatch Center Plant Held for Future Use	A.1.c	-	Direct	100.0000%	-	FF1 214
4	Dispatch Center Related Depreciation Reserve	A.1.d					
5	Dispatch Center Depreciation Reserve		(3,772,855)	Direct	100.0000%	(3,772,855)	FF1 219.25b (part)
6	Transmission Related General Depreciation Reserve		(62,122,279)	W&S	1.5514%	(963,753)	FF1 219.28b
7	Total Dispatch Center Related Depreciation Reserve		(65,895,134)			(4,736,608)	Line 5 + Line 6
8	Dispatch Center Related Accumulated Deferred Taxes	A.1.e					
9	Accumulated Deferred Income Taxes - Accelerated Amortization Property (Acct #281)		-	Plant	0.2485%	-	FF1 273.17k
10	Accumulated Deferred Income Taxes - Other Property (Acct #282)		(851,411,783)	Plant	0.2485%	(2,115,842)	Line 28
11	Accumulated Deferred Income Taxes - Other (Acct #283)		(583,066,335)	Plant	0.2485%	(1,448,977)	Line 31
12	Less Accumulated Deferred Income Taxes (Acct #190)		60,380,173	Plant	0.2485%	150,051	Page 234.18c
13	Total Dispatch Center Related Accumulated Deferred Taxes		(1,374,097,945)			(3,414,769)	Sum Lines 9 thru 12
14	Other Regulatory Assets	A.1.f					
15	FAS 106		773,258	W&S	1.5514%	11,996	FF1 232.1.30f
16	ASC 740 Regulatory Asset (FAS 109)		54,832,155	Plant	0.2485%	136,263	FF1 232.1.20f
17	ASC 740 Regulatory Liability (FAS 109)		(6,005,283)	Plant	0.2485%	(14,924)	FF1 278.2f
18	Total Other Regulatory Assets		49,600,130			133,336	Sum Lines 15 thru 17
19	Dispatch Center Prepayments	A.1.g					
20	Prepayments		5,639,239	W&S	1.5514%	87,486	FF1 111.57c
21	Dispatch Center Materials and Supplies	A.1.h					
			3,160,128	Plant	0.2485%	7,853	FF1 227.8c + 5c(footnote)
22	Dispatch Center Related Cash Working Capital	A.1.i					
23	Dispatch Center Operation and Maintenance Expense		2,488,437	WC	12.5000%	311,055	Sheet 4, Line 13(f)
24	Dispatch Center Related Administrative and General Expense		2,192,510	WC	12.5000%	274,064	Sheet 4, Line 25(f)
25	Total Dispatch Center Related Cash Working Capital		4,680,947			585,118	Line 23 + Line 24
26	(d) Account 282		851,411,783	FF1 275.9k			
27	less amounts related to divestiture		-	FF1 275.4k			
28	Total Account 282		851,411,783	Sum line 26 thru line 27			
29	(e) Account 283		624,400,051	FF1 277.9k			
30	less amounts related to divestiture		(41,333,716)	FF1 277.9k(footnote)			
31	Total Account 283		583,066,335	Sum line 29 thru line 30			

Notes:

Description	Allocation Factor	Reference
Direct Allocation (Direct)	100.0000%	
Wages & Salary Allocation (W&S)	1.5514%	Sheet 6, Line 6(c)
Plant Allocation Allocation (Plant)	0.2485%	Sheet 6, Line 16(c)
Cash Working Capital (WC)	12.5000%	OATT - Schedule 1, A.1.i

NSTAR Electric Company
Dispatch Center Expenses
Cost Year: 2011
Sheet 4

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line	Description	Tariff Section	Total	Allocator	Allocation Factor	Dispatch Center Allocated	Reference
1	Dispatch Center Depreciation Expense	B					
2	Dispatch Center Depreciation		275,575	Direct	100.0000%	275,575	See Line 36
3	General Depreciation		8,792,591	W&S	1.5514%	136,407	FF1 336.10f
4	Total Dispatch Center Depreciation Expense		9,068,166			411,982	Line 2 + Line 3
5	Dispatch Center Related Amortization of Investment Tax Credits	C	(1,385,383)	Plant	0.2485%	(3,443)	FF1 266.8f & 11f
6	Dispatch Center Related Municipal Tax Expense	D	100,681,628	Plant	0.2485%	250,204	FF1 263.5i
7	Dispatch Center Operations & Maintenance Expense	F					
8	Load dispatching #561		-	Direct	100.0000%	-	FF1 321.84b
9	Load dispatching - Reliability #561.1		1,012,879	Direct	100.0000%	1,012,879	FF1 321.85b
10	Load dispatching - Mon & Oper Trans System 561.2		983,654	Direct	100.0000%	983,654	FF1 321.86b
11	Load dispatching - Trans Service & Scheduling #561.3		491,904	Direct	100.0000%	491,904	FF1 321.87b
12	Scheduling, System Control and Dispatch Services #561.4		11,134,687		0.0000%	-	FF1 321.88b
13	Total Dispatch Center O&M Expense		13,623,124			2,488,437	Sum Lines 8 thru 12
14	Dispatch Center Related Administrative & General Expenses	G					
15	Administrative and General Expenses		151,807,508				FF1 323.197b
16	less Office Supplies and Expenses (921)		(113,082)				FF1: Page 323.182(b) footnote
17	less Outside Services Employed (923)		(1,273,126)				FF1: Page 323.184(b) footnote
18	less Property Insurance (Acct #924)		(498,584)				FF1 323.185b
19	less Regulatory Commission Expenses (Acct #928)		(8,347,816)				FF1 323.189b
20	less General Advertising Expenses (Acct #930.1)		(594,986)				FF1 323.191b
21	Subtotal		140,979,914	W&S	1.5514%	2,187,135	Sum Lines 15 thru 20
22	Property Insurance		498,584	Plant	0.2485%	1,239	FF1 323.185b
23	Transmission Related Regulatory Commission Expenses		1,664,253	Plant	0.2485%	4,136	FF1 350.7d
24	Transmission Related General Advertising Expense		-		0.0000%	-	
25	Total Dispatch Center Related A&G Expenses		143,142,751			2,192,510	Sum Lines 21 thru 24
26	Dispatch Center Related Payroll Tax Expense	E	10,728,162	W&S	1.5514%	166,435	FF1 263.8i
27	NOTES:						
28	Description	Allocation Factor	Reference				
29	Direct Allocation (Direct)	100.0000%					
30	Wages & Salaries Allocation (W&S)	1.5514%	Sheet 6, Line 6(c)				
31	Plant Allocation (Plant)	0.2485%	Sheet 6, Line 16(c)				
32	Description	Total Investment	Life Depr. Rate	Depreciation Expense	Reference		
33	Mass. Ave. Service Center - 421 (Trans. & Conversion Station Structures)	2,816,142	2.19%	61,674	Sheet 6, Line 9(c)		
34	Mass. Ave. Service Center - 431 (Trans. Station Equipment)	7,916,648	2.53%	200,291	Sheet 6, Line 10(c)		
35	SCADA Mass. Ave. - 431 (Trans. Station Equipment)	537,962	2.53%	13,610	Sheet 6, Line 11(c)		
36	Total	11,270,751		275,575	Sum Lines 33 thru 35		

Attachment 7

Service List of State Regulators and Other Interested Parties

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Attachment 8

Service List of Participating Transmission Owners

**Service List of
Participating Transmission Owners**

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