Michael J. Hall
Chair - PTO AC Legal Working Group

July 29, 2011

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, 2011, 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, 2011 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 2010 and estimated cost data for calendar year 2011 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

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[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, 2011 through May 31, 2012. 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, 2011 and forecasted MPRP and NEEWS CWIP as of December 31, 2011. 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 2009 actual data, plus 2010 forecasted data, and the revenue requirements for 2010 based on actual data.

Pursuant to Attachment F of the ISO Tariff, the annual formula rates have been updated to reflect actual 2010 cost data, Forecasted Transmission Revenue Requirements associated with projected PTF additions for 2011 (i.e. the Forecast Period), and the Annual True-up including

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[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).

[8] This includes a true-up by Northeast Utilities of its PTF revenue requirements for prior years, to reflect the recent ISO determinations regarding the cost allocation for the regional Middletown-Norwalk and Glenbrook Cables Projects. The United Illuminating Company has also reflected an estimated reduction to its forecasted revenue requirements for 2011 to reflect the ISO determination on the Middletown-Norwalk Project..

associated interest. This annual update results in a Pool RNS Rate of $63.88/kW-year effective June 1, 2011 through May 31, 2012. The new rate represents a decrease of ($0.94) from the Pool RNS Rate of $64.83/kW-year that went into effect on June 1, 2010. 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 $1.58/kW-year effective June 1, 2011. This represents a decrease of ($0.07)/kW-year over the Schedule 1 charge of $1.65/kW-year based on 2009 data that went into effect as of June 1, 2010.

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, 2011 – May 31, 2012 based on 2010 actual data and 2011 forecasted data;
- Attachment 2 - PTOs’ Annual Transmission Revenue Requirement calculations pursuant to Attachment F based on 2010 actual data and 2011 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 2011;
- Attachment 4 – Annual True-up Summary;
- Attachment 5 - Schedule 1 Rates effective June 1, 2011 through May 31, 2012, based on 2010 data;
- Attachment 6 - PTOs’ Annual Revenue Requirement calculations pursuant to Schedule 1, based on 2010 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, 2011 – May 31, 2012
Based on 2010 Actual Data, 2011 Forecasted Data and Annual True-up

PTO 2010 12 CP NETWORK LOADS

Local Networks	2010 Network Load (MW)
NSTAR	**4,408.135**
Bangor Hydro Electric	**261.303**
Fitchburg Gas & Electric	**79.033**
Central Maine Power	**1,431.673**
National Grid	**6,046.299**
Northeast Utilities	**7,268.552**
United Illuminating	**755.404**
VTransco	**836.022**
Total	**21,086.421**

Long Term TOUT (MW)	**0**

PTO RNS Rates for 6/1/11	PRE 97 RNS Rate	Post 96 RNS Rate	RNS Rates for June 1, 2011	RNS Rates previously in effect June 1, 2010	Delta
Total NE Rev Req	$279,971,076	$1,067,109,439			
Total NE Loads - kw	21,086,421	21,086,421			
Total NE RNS $ / kw-yr.	13.27732	50.60648	63.88380	64.82684	(0.94304)

				PTO 2010 Rev Req			
				PTO Annual Input Data 2010			
					PTF Revenue Requirements		
					Pre-1997	Post-1996	
		Customer #	DUNS #	DUNS Name	PTF	PTF	
					$	$	
1	*	1	83-729-7852	Ashburnham Municipal Light Dept.	$6,354	$0	1
2		2	00-694-9002	**Bangor Hydro Transmission**	$1,163,943	$39,299,710	2
3	*	4	XX-040-0000	Boylston Municipal Light Dept.	$7,702	$0	3
4		5	17-057-1897	Braintree Electric Light Dept.	$250,303	$2,366,985	4
5		6	00-694-8954	**Central Maine Power Transmission**	$15,626,275	$143,306,968	5
6	*	7	11-468-3899	Chicopee Municipal Lighting Plant	$32,601	$0	6
7	*	90	07-952-6729	Concord Municipal Light Dept.	$12,419	$0	7
8		8	09-207-8351	Conn Municipal Electric Energy Coop.	$242,038	$1,209,969	8
9		51386	96-733-8696	Connecticut Transmission Municipal Electric	$0	$7,378,334	9
10	*	9	15-596-9157	Danvers Electric Dept.	$92,649	$0	10
11	*	39	15-596-9983	Georgetown Municipal Light Dept.	$8,167	$0	11
12	*	40	15-601-8301	Groton Electric Light Dept.	$10,422	$0	12
13		38	00-695-4317	**Fitchburg Gas & Electric Light Co.**	$187,127	$107,085	13
14	*	42	14-703-0704	Hingham Municipal Lighting Plant	$40,967	$0	14
15	*	43	87-808-0563	Holden Municipal Light Dept.	$31,110	$0	15
16		44	08-465-0050	Holyoke Gas & Electric Dept.	$864,708	$453,742	16
17		45	10-775-5126	Hudson Light & Power Dept.	$111,330	$0	17
18	*	72	13-661-7155	Hull Municipal Lighting Plant	$14,280	$0	18
19	*	73	15-586-9563	Ipswich Municipal Light Dept.	$7,747	$0	19
20	*	75	79-432-5019	Littleton Electric Light & Water Dept.	$15,966	$0	20
21		6	06-099-4258	Maine Electric Power Company	($1,579,725)	($334,571)	21
22	*	77	95-690-6051	Mansfield Municipal Electric Dept.	$64,535	$0	22
23	*	78	15-598-9544	Marblehead Municipal Light Dept.	$22,521	$0	23
24	*	79	15-597-6665	Middleborough Gas & Electric Dept.	$42,250	$0	24
25	*	80	18-675-8231	Middleton Municipal Electric Dept.	$24,113	$0	25
26		81	00-695-2881	**National Grid**	$80,273,925	$117,359,995	26
27		51321	83-132-2677	New Hampshire Transmission, LLC	$4,164,343	$9,487,858	27
28	*	111	13-938-4465	North Attleboro Electric Dept.	$38,005	$0	28
29		112	95-910-8929	**Northeast Utilities Transmission**	$91,401,457	$476,165,258	29
30		158	08-421-1572	Norwood Municipal Light Plant	$0	$2,650,125	30
31		3	00-695-1552	**NSTAR**	$53,644,648	$108,409,378	31
32	*	116	06-984-9461	Pascoag Fire District - Electric Dept	$8,009	$0	32
33	*	117	15-582-5391	Paxton Municipal Light Department	$7,216	$0	33
34	*	144	10-371-6353	Peabody Municipal Light Plant	$99,359	$0	34
35		148	86-703-4654	Reading Municipal Light Dept.	$375,135	$316,377	35
36	*	146	11-885-5188	Rowley Municipal Lighting Plant	$1,630	$0	36
37	*	149	78-451-8870	Shrewsbury Electric Light Plant	$56,989	$0	37
38	*	152	15-586-0620	Sterling Municipal Electric Light Dept.	$11,805	$0	38
39	*	150	19-548-8630	South Hadley Electric Light Dept.	$50,143	$0	39
40		153	04-661-6033	Taunton Municipal Lighting Plant	$268,978	$0	40
41	*	180	02-619-2302	Templeton Municipal Lighting Plant	$18,267	$0	41
42	*	185	79-806-8342	Unitil Power Corp	$124,419	$0	42
43		181	00-691-7967	**The United Illuminating Company**	$20,876,926	$64,511,355	43
44		50853	78-039-9163	**Vermont Trans**	$11,102,488	$89,091,802	44
45		182	00-579-1934	Vermont Electric Power Co, Inc.	$0	$5,329,069	45
46	*	183	15-415-7622	Wakefield Municipal Light Dept	$42,394	$0	46
47	*	186	12-787-0350	West Boylston Municipal Light Plant	$17,616	$0	47
48	*	187	12-757-5165	Westfield Gas & Electric Light Dept.	$87,522	$0	48
49				**Total**	$279,971,076	$1,067,109,439	49
	*	Revenue requirement amounts indicate payments made to support PTF owned by other Participants.					

NETWORK LOAD VALUE (kW)

					Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Total Annual Network Load	Average Monthly Network Load
				Total Local Network Load (kW):	19,692,341	19,002,861	17,884,572	16,177,351	22,482,467	23,979,756	26,696,595	25,232,215	25,550,519	17,972,738	17,999,693	20,365,818	253,036,926	21,086,421
Local Network ID	**Local Network Name**																	
1	BE				3,996,463	3,800,374	3,636,446	3,373,542	4,705,658	5,183,416	5,627,255	5,343,435	5,407,071	4,114,490	3,599,299	4,110,140	52,897,589	4,408,135
2	BHE				259,014	255,954	241,780	216,707	250,832	250,108	293,867	304,254	308,704	238,555	250,963	264,894	3,135,632	261,303
4	CMP				1,428,622	1,401,608	1,320,141	1,183,150	1,419,192	1,389,328	1,598,002	1,599,651	1,604,426	1,326,342	1,382,391	1,527,230	17,180,083	1,431,673
6	NEP				5,510,344	5,367,135	5,132,475	4,586,944	6,454,677	7,028,884	7,707,244	7,376,371	7,415,825	5,142,677	5,079,413	5,753,513	72,555,502	6,046,299
7	NU				6,886,567	6,615,613	6,105,117	5,479,252	7,927,226	8,296,472	9,386,673	8,677,493	8,856,360	5,747,362	6,197,745	7,046,737	87,222,617	7,268,552
8	UI				673,518	654,718	616,254	577,671	793,371	922,248	1,018,517	935,281	946,311	610,120	624,164	692,664	9,064,837	755,404
9	VELCO/VT Transco				862,181	833,223	762,799	696,510	847,085	826,446	972,059	903,568	920,042	725,300	791,744	891,313	10,032,270	836,022
15	FGE				75,632	74,236	69,560	63,575	84,426	82,854	92,978	92,162	91,780	67,892	73,974	79,327	948,396	79,033

NETWORK LOAD VALUE (kW)

				Total Network Load (kW)	19,692,341	19,002,861	17,884,572	16,177,351	22,482,467	23,979,756	26,696,595	25,232,215	25,550,519	17,972,738	17,999,693	20,365,818	253,036,926	21,086,421

Local Network ID	Local Network Name	Network Load ID	Duns Number	Network Load Name	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Total Annual Network Load	Average Monthly Network Load
1	BE	2	17-057-1897	Braintree	62,273	59,033	57,747	52,127	75,095	83,420	87,901	84,201	85,161	64,730	55,862	64,775	832,325	69,360
1	BE	4	07-952-6729	Concord	30,168	28,847	27,643	25,447	40,798	39,959	44,983	40,997	42,184	27,556	27,073	32,075	407,730	33,978
1	BE	5	14-703-0704	Hingham	31,340	31,364	30,480	26,260	43,584	48,824	53,340	46,724	48,824	36,556	30,428	34,656	462,380	38,532
1	BE	6	13-661-7155	Hull	8,219	9,282	8,625	5,606	8,513	11,069	13,437	12,282	12,727	8,354	8,216	10,021	116,351	9,696
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)	49,995	44,415	46,935	47,160	68,805	73,800	77,805	73,935	75,555	56,700	45,945	50,985	712,035	59,336
1	BE	11	00-695-2626	MECO - Quincy/Wey. (R W)	205,735	199,167	189,382	153,966	231,541	252,566	278,779	258,223	264,113	189,663	182,141	215,062	2,620,338	218,362
1	BE	13	86-703-4654	Reading	74,988	74,880	70,296	68,988	103,800	105,432	114,624	109,332	110,328	75,816	73,056	79,356	1,060,896	88,408
1	BE	14	17-819-3330	Wellseley	41,914	40,433	37,678	34,900	59,357	58,096	64,709	60,686	61,213	41,806	37,884	45,386	584,062	48,672
1	BE	15	07-382-0680	Belmont (PASNY)	22,253	22,270	21,269	15,614	27,171	27,674	32,414	30,655	30,689	19,733	20,432	23,822	293,996	24,500
2	BHE	16	00-694-9002	Bangor Hydro Electric	253,448	250,360	236,785	212,656	246,393	245,876	288,837	298,563	302,896	234,024	245,573	258,771	3,074,182	256,182
2	BHE	17	00-694-8954	CMP - Herman Sub	5,566	5,594	4,995	4,051	4,439	4,232	5,030	5,691	5,808	4,531	5,390	6,123	61,450	5,121
4	CMP	21	00-694-8954	Central Maine Power	1,353,609	1,328,221	1,248,702	1,099,598	1,350,988	1,317,559	1,527,915	1,527,686	1,539,454	1,256,448	1,310,833	1,459,913	16,320,926	1,360,077
4	CMP	22	11-923-4722	NP - Fox Island	1,431	1,474	1,328	1,237	1,233	1,496	1,796	1,662	1,535	1,402	1,414	1,504	17,512	1,459
4	CMP	23	05-448-1341	NP - Kennebunk	16,626	16,057	15,230	12,410	16,322	16,497	19,788	18,983	18,926	14,148	14,767	16,847	196,601	16,383
4	CMP	24	05-448-1341	FPL-Madison	46,840	47,880	45,300	48,730	41,790	47,460	41,030	43,630	36,880	48,270	48,570	41,510	537,890	44,824
6	NEP	31	00-695-2881	New England Power	146	142	117	73	37	27	35	38	39	35	128	144	961	80

NETWORK LOAD VALUE (kW)

					Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Total Annual Network Load	Average Monthly Network Load
				Total Local Network Load (kW):	19,692,341	19,002,861	17,884,572	16,177,351	22,482,467	23,979,756	26,696,595	25,232,215	25,550,519	17,972,738	17,999,693	20,365,818	253,036,926	21,086,421
Local Network ID	**Local Network Name**																	
1	BE				3,996,463	3,800,374	3,636,446	3,373,542	4,705,658	5,183,416	5,627,255	5,343,435	5,407,071	4,114,490	3,599,299	4,110,140	52,897,589	4,408,135
2	BHE				259,014	255,954	241,780	216,707	250,832	250,108	293,867	304,254	308,704	238,555	250,963	264,894	3,135,632	261,303
4	CMP				1,428,622	1,401,608	1,320,141	1,183,150	1,419,192	1,389,328	1,598,002	1,599,651	1,604,426	1,326,342	1,382,391	1,527,230	17,180,083	1,431,673
6	NEP				5,510,344	5,367,135	5,132,475	4,586,944	6,454,677	7,028,884	7,707,244	7,376,371	7,415,825	5,142,677	5,079,413	5,753,513	72,555,502	6,046,299
7	NU				6,886,567	6,615,613	6,105,117	5,479,252	7,927,226	8,296,472	9,386,673	8,677,493	8,856,360	5,747,362	6,197,745	7,046,737	87,222,617	7,268,552
8	UI				673,518	654,718	616,254	577,671	793,371	922,248	1,018,517	935,281	946,311	610,120	624,164	692,664	9,064,837	755,404
9	VELCO/VT Transco				862,181	833,223	762,799	696,510	847,085	826,446	972,059	903,568	920,042	725,300	791,744	891,313	10,032,270	836,022
15	FGE				75,632	74,236	69,560	63,575	84,426	82,854	92,978	92,162	91,780	67,892	73,974	79,327	948,396	79,033

NETWORK LOAD VALUE (kW)

Total Network Load (kW)	19,692,341	19,002,861	17,884,572	16,177,351	22,482,467	23,979,756	26,696,595	25,232,215	25,550,519	17,972,738	17,999,693	20,365,818	253,036,926	21,086,421

Local Network ID	Local Network Name	Network Load ID	Duns Number	Network Load Name	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Total Annual Network Load	Average Monthly Network Load
6	NEP	32	00-695-2261	Granite St. Elec.(R W)	138,593	137,912	129,442	121,403	177,216	166,910	194,187	185,105	185,215	127,933	133,768	148,167	1,845,851	153,821
6	NEP	34	00-119-3655	Narragansett Electric	1,250,656	1,213,774	1,168,179	1,038,959	1,457,649	1,695,979	1,831,634	1,741,049	1,754,382	1,240,623	1,148,934	1,300,679	16,842,497	1,403,541
6	NEP	35	83-729-7852	Ashburnham	6,327	6,043	5,710	4,558	5,203	5,438	6,360	5,837	5,888	4,428	5,662	6,389	67,843	5,654
6	NEP	36	00-695-1552	Boston Edison Co.	27,533	43,999	42,264	41,113	51,947	53,190	57,004	58,097	58,482	46,201	44,447	28,765	553,042	46,087
6	NEP	37	XX-040-0000	Boylston	5,534	5,322	4,869	4,092	5,937	6,028	7,086	6,633	6,532	3,972	4,748	5,856	66,609	5,551
6	NEP	38	96-258-1922	VELCO - Central Vt Pub. Ser.	9,360	9,266	8,395	7,145	9,184	8,677	11,011	10,100	9,910	7,763	8,841	9,998	109,650	9,138
6	NEP	39	15-596-9157	Danvers	54,922	52,445	50,140	43,056	67,162	73,526	78,308	74,506	75,687	53,482	47,636	56,016	726,886	60,574
6	NEP	41	00-695-6551	NU - French King	9,723	9,377	8,681	6,950	8,717	10,028	11,175	9,070	9,126	7,474	8,237	10,246	108,804	9,067
6	NEP	42	15-596-9983	Georgetown	8,718	8,607	8,450	7,218	10,644	11,104	13,090	12,275	12,227	7,457	8,598	9,640	118,028	9,836
6	NEP	44	15-601-8301	Groton MA	12,803	12,674	12,029	10,041	13,497	14,274	17,707	16,830	16,856	10,196	11,848	13,577	162,332	13,528
6	NEP	45	15-601-8285	NP - Groveland	6,393	6,315	5,773	5,073	8,156	7,979	9,930	10,521	10,639	6,334	7,063	7,644	91,820	7,652
6	NEP	46	87-808-0563	Holden	17,998	17,748	15,985	13,130	18,044	18,486	21,154	20,062	20,426	14,241	16,665	18,579	212,518	17,710
6	NEP	47	10-775-5126	Hudson	55,860	54,306	52,556	50,800	67,124	70,824	73,904	71,892	73,332	54,880	51,156	56,980	733,614	61,135
6	NEP	48	15-586-9563	Ipswich	18,885	18,103	17,082	14,303	22,407	24,350	26,989	25,502	26,411	18,395	17,320	19,903	249,650	20,804
6	NEP	49	79-432-5019	Littleton MA	40,038	39,502	38,275	35,234	50,665	49,542	53,499	51,322	51,339	39,761	38,638	43,044	530,859	44,238
6	NEP	50	09-551-3214	NP - Littleton NH	11,606	11,685	10,588	9,312	12,121	12,693	13,558	13,154	13,554	10,647	11,458	12,545	142,921	11,910
6	NEP	51	95-690-6051	Mansfield	36,201	35,813	34,257	32,213	46,239	51,897	54,850	51,638	52,156	37,915	33,379	38,016	504,574	42,048

NETWORK LOAD VALUE (kW)

					Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Total Annual Network Load	Average Monthly Network Load
				Total Local Network Load (kW):	19,692,341	19,002,861	17,884,572	16,177,351	22,482,467	23,979,756	26,696,595	25,232,215	25,550,519	17,972,738	17,999,693	20,365,818	253,036,926	21,086,421
Local Network ID	**Local Network Name**																	
1	BE				3,996,463	3,800,374	3,636,446	3,373,542	4,705,658	5,183,416	5,627,255	5,343,435	5,407,071	4,114,490	3,599,299	4,110,140	52,897,589	4,408,135
2	BHE				259,014	255,954	241,780	216,707	250,832	250,108	293,867	304,254	308,704	238,555	250,963	264,894	3,135,632	261,303
4	CMP				1,428,622	1,401,608	1,320,141	1,183,150	1,419,192	1,389,328	1,598,002	1,599,651	1,604,426	1,326,342	1,382,391	1,527,230	17,180,083	1,431,673
6	NEP				5,510,344	5,367,135	5,132,475	4,586,944	6,454,677	7,028,884	7,707,244	7,376,371	7,415,825	5,142,677	5,079,413	5,753,513	72,555,502	6,046,299
7	NU				6,886,567	6,615,613	6,105,117	5,479,252	7,927,226	8,296,472	9,386,673	8,677,493	8,856,360	5,747,362	6,197,745	7,046,737	87,222,617	7,268,552
8	UI				673,518	654,718	616,254	577,671	793,371	922,248	1,018,517	935,281	946,311	610,120	624,164	692,664	9,064,837	755,404
9	VELCO/VT Transco				862,181	833,223	762,799	696,510	847,085	826,446	972,059	903,568	920,042	725,300	791,744	891,313	10,032,270	836,022
15	FGE				75,632	74,236	69,560	63,575	84,426	82,854	92,978	92,162	91,780	67,892	73,974	79,327	948,396	79,033

NETWORK LOAD VALUE (kW)

				Total Network Load (kW)	19,692,341	19,002,861	17,884,572	16,177,351	22,482,467	23,979,756	26,696,595	25,232,215	25,550,519	17,972,738	17,999,693	20,365,818	253,036,926	21,086,421

Local Network ID	Local Network Name	Network Load ID	Duns Number	Network Load Name	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Total Annual Network Load	Average Monthly Network Load
6	NEP	53	15-598-9544	Marblehead	19,701	19,692	18,504	15,093	19,674	23,940	27,233	26,091	27,279	15,759	17,910	21,285	252,161	21,013
6	NEP	54	92-933-1452	Massachusetts Development Fin	23,597	23,607	23,558	24,461	29,771	30,989	32,422	31,343	32,256	27,877	24,874	24,766	329,521	27,460
6	NEP	55	78-609-1892	NP - Merrimac	5,383	5,452	4,869	4,084	6,159	6,243	8,107	7,371	7,473	3,913	4,994	5,764	69,812	5,818
6	NEP	56	18-675-8231	Middleton	15,068	15,431	14,238	12,925	21,911	22,550	23,950	23,621	23,354	15,690	15,371	16,140	220,249	18,354
6	NEP	57	13-938-4465	N. Attleboro	40,896	39,552	37,920	33,360	47,440	53,168	56,816	53,712	53,968	37,088	36,720	43,104	533,744	44,479
6	NEP	60	15-582-5391	Paxton	4,409	4,419	4,145	3,491	3,984	4,210	4,877	4,596	4,514	2,903	4,298	4,900	50,746	4,229
6	NEP	61	10-371-6353	Peabody	82,500	79,300	74,600	69,400	101,700	112,300	124,200	119,300	119,000	78,900	73,400	86,700	1,121,300	93,442
6	NEP	62	96-152-2786	NP - Princeton	3,214	3,048	2,893	2,282	2,541	2,501	3,222	3,011	2,982	2,037	2,912	3,415	34,058	2,838
6	NEP	63	11-885-5188	Rowley	7,136	7,039	6,642	5,482	9,198	9,824	11,778	10,446	10,865	6,687	6,806	7,908	99,811	8,318
6	NEP	64	78-451-8870	Shrewsbury	50,872	48,852	45,216	40,983	59,461	57,600	51,393	62,789	61,788	37,987	44,525	52,258	613,724	51,144
6	NEP	65	15-586-0620	Sterling	9,105	9,002	8,656	7,468	10,512	11,221	11,883	11,855	11,467	8,062	8,862	9,612	117,705	9,809
6	NEP	66	02-619-2302	Templeton	10,009	9,984	9,213	7,600	8,689	8,700	9,778	9,536	9,879	7,691	9,339	10,140	110,558	9,213
6	NEP	67	15-415-7622	Wakefield	30,408	29,854	28,342	25,485	38,707	41,580	46,989	44,671	41,227	29,820	28,913	33,920	419,916	34,993
6	NEP	68	12-787-0350	W.Boylston	9,576	9,092	8,850	7,328	11,028	11,310	12,802	11,915	12,025	8,185	8,870	10,695	121,676	10,140
7	NU	70	00-694-8954	CMP - Bolt Hill	37,773	37,639	36,205	33,694	38,457	47,392	54,768	53,525	56,368	41,963	40,903	40,909	519,596	43,300
7	NU	71	11-468-3899	Chicopee	69,198	69,261	60,123	54,652	74,721	80,398	88,189	83,375	85,191	54,717	61,154	77,012	857,991	71,499
7	NU	72	96-165-7079	Conn. Mun. Elec. Enr. Co	273,727	263,105	246,589	247,762	314,042	323,450	330,968	330,605	333,898	217,048	262,440	234,662	3,378,296	281,525

NETWORK LOAD VALUE (kW)

					Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Total Annual Network Load	Average Monthly Network Load
				Total Local Network Load (kW):	19,692,341	19,002,861	17,884,572	16,177,351	22,482,467	23,979,756	26,696,595	25,232,215	25,550,519	17,972,738	17,999,693	20,365,818	253,036,926	21,086,421
Local Network ID	**Local Network Name**																	
1	BE				3,996,463	3,800,374	3,636,446	3,373,542	4,705,658	5,183,416	5,627,255	5,343,435	5,407,071	4,114,490	3,599,299	4,110,140	52,897,589	4,408,135
2	BHE				259,014	255,954	241,780	216,707	250,832	250,108	293,867	304,254	308,704	238,555	250,963	264,894	3,135,632	261,303
4	CMP				1,428,622	1,401,608	1,320,141	1,183,150	1,419,192	1,389,328	1,598,002	1,599,651	1,604,426	1,326,342	1,382,391	1,527,230	17,180,083	1,431,673
6	NEP				5,510,344	5,367,135	5,132,475	4,586,944	6,454,677	7,028,884	7,707,244	7,376,371	7,415,825	5,142,677	5,079,413	5,753,513	72,555,502	6,046,299
7	NU				6,886,567	6,615,613	6,105,117	5,479,252	7,927,226	8,296,472	9,386,673	8,677,493	8,856,360	5,747,362	6,197,745	7,046,737	87,222,617	7,268,552
8	UI				673,518	654,718	616,254	577,671	793,371	922,248	1,018,517	935,281	946,311	610,120	624,164	692,664	9,064,837	755,404
9	VELCO/VT Transco				862,181	833,223	762,799	696,510	847,085	826,446	972,059	903,568	920,042	725,300	791,744	891,313	10,032,270	836,022
15	FGE				75,632	74,236	69,560	63,575	84,426	82,854	92,978	92,162	91,780	67,892	73,974	79,327	948,396	79,033

NETWORK LOAD VALUE (kW)

				Total Network Load (kW)	19,692,341	19,002,861	17,884,572	16,177,351	22,482,467	23,979,756	26,696,595	25,232,215	25,550,519	17,972,738	17,999,693	20,365,818	253,036,926	21,086,421
Local Network ID	**Local Network Name**	**Network Load ID**	**Duns Number**	**Network Load Name**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Total Annual Network Load**	**Average Monthly Network Load**
7	NU	73	08-465-0050	Holyoke	52,835	53,647	49,972	46,176	68,747	69,375	75,846	72,261	74,820	50,161	53,189	59,197	726,226	60,519
7	NU	74	00-695-2626	Mass Elec - SBNG (R W)	91,440	83,752	74,197	64,331	96,475	92,102	119,155	102,019	107,268	68,969	76,904	95,925	1,072,537	89,378
7	NU	76	19-548-8630	S.Hadley	19,654	19,513	17,816	15,647	24,070	22,414	27,599	25,455	25,766	16,715	18,039	20,731	253,419	21,118
7	NU	77	00-691-7967	UI S/S	214,209	204,277	193,815	186,060	260,121	302,877	335,602	304,092	306,563	187,930	194,237	219,024	2,908,807	242,401
7	NU	79	12-757-5165	NP - Chester	1,121	1,077	843	667	728	822	909	840	814	713	912	1,041	10,487	874
7	NU	80	12-757-5165	Westfield	57,636	56,996	54,027	50,039	74,792	73,880	85,759	80,784	83,762	52,640	55,636	61,917	787,868	65,656
8	UI	81	00-691-7967	United Illuminating	665,367	644,664	607,874	567,765	791,887	918,465	1,014,832	932,334	945,148	602,114	613,302	685,538	8,989,290	749,108
9	VELCO/VT Tr	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	142,137	139,743	107,392	83,880	110,287	111,044	143,937	129,275	130,746	94,647	108,681	147,246	1,449,015	120,751
8	UI	84	00-691-7090	NU-Branford Railroad 48R Substation	3,399	2,302	2,188	3,426	1,484	3,783	3,685	2,947	1,163	2,534	3,518	3,676	34,105	2,842
6	NEP	85	00-881-9492	New Hampshire Electric Co-op	2,094	2,098	2,017	1,457	1,588	1,554	1,925	1,787	1,752	1,254	1,886	2,206	21,618	1,802
4	CMP	89	84-173-9824	NP - Gates Formed Fibre	2,204	1,418	1,292	1,761	2,129	2,206	2,241	2,095	1,984	1,613	2,083	1,956	22,982	1,915
6	NEP	91	86-703-4654	North Reading	29,792	29,932	29,231	27,818	46,832	47,099	41,780	50,700	51,235	29,728	30,199	34,258	448,604	37,384
7	NU	94	00-697-1352	Citizens Utilites	209	217	178	138	142	135	199	165	174	176	211	267	2,211	184
7	NU	95	11-923-4722	Ashland	3,128	3,256	2,805	2,101	2,686	3,004	3,424	2,930	2,949	2,355	2,722	3,326	34,686	2,891
7	NU	96	11-923-4722	New Hampton	580	615	589	406	506	453	502	479	467	480	566	646	6,289	524
4	CMP	97	05-448-1341	FPL Energy	2,380	1,053	3,396	1,579	2,069	9	0	112	150	18	44	0	10,810	901

NETWORK LOAD VALUE (kW)

					Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Total Annual Network Load	Average Monthly Network Load
				Total Local Network Load (kW):	19,692,341	19,002,861	17,884,572	16,177,351	22,482,467	23,979,756	26,696,595	25,232,215	25,550,519	17,972,738	17,999,693	20,365,818	253,036,926	21,086,421
Local Network ID	**Local Network Name**																	
1	BE				3,996,463	3,800,374	3,636,446	3,373,542	4,705,658	5,183,416	5,627,255	5,343,435	5,407,071	4,114,490	3,599,299	4,110,140	52,897,589	4,408,135
2	BHE				259,014	255,954	241,780	216,707	250,832	250,108	293,867	304,254	308,704	238,555	250,963	264,894	3,135,632	261,303
4	CMP				1,428,622	1,401,608	1,320,141	1,183,150	1,419,192	1,389,328	1,598,002	1,599,651	1,604,426	1,326,342	1,382,391	1,527,230	17,180,083	1,431,673
6	NEP				5,510,344	5,367,135	5,132,475	4,586,944	6,454,677	7,028,884	7,707,244	7,376,371	7,415,825	5,142,677	5,079,413	5,753,513	72,555,502	6,046,299
7	NU				6,886,567	6,615,613	6,105,117	5,479,252	7,927,226	8,296,472	9,386,673	8,677,493	8,856,360	5,747,362	6,197,745	7,046,737	87,222,617	7,268,552
8	UI				673,518	654,718	616,254	577,671	793,371	922,248	1,018,517	935,281	946,311	610,120	624,164	692,664	9,064,837	755,404
9	VELCO/VT Transco				862,181	833,223	762,799	696,510	847,085	826,446	972,059	903,568	920,042	725,300	791,744	891,313	10,032,270	836,022
15	FGE				75,632	74,236	69,560	63,575	84,426	82,854	92,978	92,162	91,780	67,892	73,974	79,327	948,396	79,033

NETWORK LOAD VALUE (kW)

	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10		
Total Network Load (kW)	19,692,341	19,002,861	17,884,572	16,177,351	22,482,467	23,979,756	26,696,595	25,232,215	25,550,519	17,972,738	17,999,693	20,365,818	253,036,926	21,086,421

Local Network ID	Local Network Name	Network Load ID	Duns Number	Network Load Name	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Total Annual Network Load	Average Monthly Network Load
6	NEP	98	04-661-6033	Taunton	107,690	105,640	102,560	93,360	133,450	152,700	159,870	152,800	152,910	115,150	102,780	113,440	1,492,350	124,363
6	NEP	99	XX-XXX-0001	NP - MBTA - EUA	460	224	453	197	37	36	37	37	37	36	210	217	1,981	165
6	NEP	100	15-597-6665	Middleboro	39,248	38,976	37,508	33,479	47,598	57,201	60,557	55,752	57,210	41,395	38,142	42,427	549,493	45,791
6	NEP	101	06-984-9461	Pascoag	8,962	8,856	8,453	7,330	9,683	10,991	12,355	11,379	11,606	8,362	8,835	10,015	116,827	9,736
6	NEP	102	00-697-1352	Public Service of NH	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	NEP	103	01-821-3640	ANP Bellingham	0	0	2,000	0	0	0	0	0	0	0	1,000	0	3,000	250
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	4,752	4,752	6,192	6,480	0	0	0	0	0	5,472	7,344	0	34,992	2,916
7	NU	108	00-378-9070	Unitil Energy Systems Inc.	195,421	193,106	180,608	159,312	241,954	235,733	291,369	270,410	274,802	173,549	186,439	211,763	2,614,466	217,872
4	CMP	111	05-448-1341	CMP FPL Madison Electric Works	5,532	5,505	4,893	17,835	4,661	4,101	5,232	5,483	5,497	4,443	4,680	5,500	73,362	6,114
9	VELCO/VT Tr	113	00-697-1352	Public Service of New Hampshire	21,972	21,771	21,129	18,892	24,240	23,200	27,693	25,251	26,413	19,639	20,511	21,720	272,431	22,703
7	NU	114	XX-XX5-5555	Town of Wolfeboro Municipal Elec Dept	11,442	11,574	9,637	7,141	11,259	11,314	14,878	12,681	13,140	8,927	10,206	12,134	134,333	11,194
9	VELCO/VT Tr	115	00-881-9492	New Hampshire Electric Co-op	2,553	2,099	1,949	1,438	1,520	1,615	1,961	1,881	1,803	1,687	1,975	2,346	22,827	1,902
9	VELCO/VT Tr	116	08-910-3543	Vermont Marble	22,456	24,921	24,672	25,633	23,346	17,668	26,759	23,451	22,385	23,525	26,173	27,515	288,504	24,042
9	VELCO/VT Tr	117	14-660-0585	Vermont Electric Cooperative	68,093	66,192	62,446	52,110	52,829	54,815	61,804	62,514	59,833	60,752	66,613	70,159	738,160	61,513
9	VELCO/VT Tr	118	02-065-4430	Burlington Electric Power	47,702	50,013	46,992	45,091	61,058	57,448	70,430	63,203	65,525	48,222	42,407	47,344	645,435	53,786
9	VELCO/VT Tr	119	11-923-4722	Vermont Public Power Supply Authority	81,359	76,312	70,707	60,487	65,150	66,344	78,041	70,198	75,862	66,303	76,495	84,078	871,336	72,611

NETWORK LOAD VALUE (kW)

					Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Total Annual Network Load	Average Monthly Network Load
				Total Local Network Load (kW):	19,692,341	19,002,861	17,884,572	16,177,351	22,482,467	23,979,756	26,696,595	25,232,215	25,550,519	17,972,738	17,999,693	20,365,818	253,036,926	21,086,421
Local Network ID	**Local Network Name**																	
1	BE				3,996,463	3,800,374	3,636,446	3,373,542	4,705,658	5,183,416	5,627,255	5,343,435	5,407,071	4,114,490	3,599,299	4,110,140	52,897,589	4,408,135
2	BHE				259,014	255,954	241,780	216,707	250,832	250,108	293,867	304,254	308,704	238,555	250,963	264,894	3,135,632	261,303
4	CMP				1,428,622	1,401,608	1,320,141	1,183,150	1,419,192	1,389,328	1,598,002	1,599,651	1,604,426	1,326,342	1,382,391	1,527,230	17,180,083	1,431,673
6	NEP				5,510,344	5,367,135	5,132,475	4,586,944	6,454,677	7,028,884	7,707,244	7,376,371	7,415,825	5,142,677	5,079,413	5,753,513	72,555,502	6,046,299
7	NU				6,886,567	6,615,613	6,105,117	5,479,252	7,927,226	8,296,472	9,386,673	8,677,493	8,856,360	5,747,362	6,197,745	7,046,737	87,222,617	7,268,552
8	UI				673,518	654,718	616,254	577,671	793,371	922,248	1,018,517	935,281	946,311	610,120	624,164	692,664	9,064,837	755,404
9	VELCO/VT Transco				862,181	833,223	762,799	696,510	847,085	826,446	972,059	903,568	920,042	725,300	791,744	891,313	10,032,270	836,022
15	FGE				75,632	74,236	69,560	63,575	84,426	82,854	92,978	92,162	91,780	67,892	73,974	79,327	948,396	79,033

NETWORK LOAD VALUE (kW)

				Total Network Load (kW)	19,692,341	19,002,861	17,884,572	16,177,351	22,482,467	23,979,756	26,696,595	25,232,215	25,550,519	17,972,738	17,999,693	20,365,818	253,036,926	21,086,421

Local Network ID	Local Network Name	Network Load ID	Duns Number	Network Load Name	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Total Annual Network Load	Average Monthly Network Load
9	VELCO/VT Tr	120	96-258-1922	Central Vermont Public Service	375,329	356,777	321,761	287,690	343,000	345,986	405,647	372,318	385,780	301,314	334,861	386,370	4,216,833	351,403
9	VELCO/VT Tr	121	03-647-6141	Green Mountain Power	229,101	220,633	204,361	198,361	267,381	249,587	287,537	273,507	271,346	195,678	205,624	233,286	2,836,402	236,367
7	NU	122	00-695-6551	Western Mass Electric Company	586,638	577,783	533,582	489,788	689,932	684,020	777,521	724,643	746,784	514,936	552,409	619,428	7,497,464	624,789
7	NU	123	00-691-7090	Connecticut Light and Power Co.	3,812,111	3,643,916	3,378,582	3,012,122	4,431,016	4,826,480	5,340,149	4,885,977	4,995,285	3,139,351	3,351,186	3,901,836	48,718,011	4,059,834
7	NU	124	00-697-1352	Public Service of New Hampshire	1,260,546	1,249,770	1,151,799	1,021,774	1,474,636	1,410,073	1,694,880	1,589,786	1,614,975	1,115,032	1,186,573	1,330,170	16,100,014	1,341,668
6	NEP	126	16-035-2865	Merrill Lynch Commodities, Inc.	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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	0	0	0	0
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	0	0	0	383	0	0	0	0	0	0	0	0	383	32
1	BE	133	00-176-6328	Massport	27,067	25,680	24,446	26,732	28,360	30,172	29,992	28,373	28,911	27,890	24,134	26,981	328,738	27,395
1	BE	136	00-695-1552	NSTAR Electric Co. (NEMASS & Boston)	2,499,054	2,383,868	2,252,265	2,241,305	3,050,314	3,225,641	3,412,098	3,307,743	3,359,119	2,645,211	2,230,750	2,539,197	33,146,565	2,762,214
1	BE	137	00-695-1552	NSTAR Electric Co. (SEMASS)	827,580	782,080	767,747	591,690	871,610	1,135,003	1,317,655	1,188,206	1,193,473	830,654	771,391	891,490	11,168,579	930,715
1	BE	138	XX-XXX-0001	MBTA - NSTAR (NEMASS & Boston)	71,195	57,717	56,183	52,188	57,817	47,602	46,479	49,948	43,455	44,421	50,276	56,929	634,210	52,851
1	BE	139	XX-XXX-0001	MBTA - NSTAR (SEMASS)	2,033	1,830	1,927	1,181	1,476	1,566	1,438	1,496	1,498	1,700	1,465	1,704	19,314	1,610
6	NEP	140	00-695-2626	Massachusetts Electric (SEMASS)	845,888	826,318	798,580	716,514	1,018,144	1,183,383	1,276,448	1,198,983	1,206,878	832,612	787,494	896,172	11,587,414	965,618
6	NEP	141	00-695-2626	Massachusetts Electric (WCMASS)	1,519,436	1,473,120	1,412,990	1,269,545	1,773,084	1,789,390	1,986,955	1,911,913	1,922,292	1,314,298	1,395,659	1,573,800	19,342,482	1,611,874

NETWORK LOAD VALUE (kW)

					Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Total Annual Network Load	Average Monthly Network Load
				Total Local Network Load (kW):	19,692,341	19,002,861	17,884,572	16,177,351	22,482,467	23,979,756	26,696,595	25,232,215	25,550,519	17,972,738	17,999,693	20,365,818	253,036,926	21,086,421
Local Network ID	**Local Network Name**																	
1	BE				3,996,463	3,800,374	3,636,446	3,373,542	4,705,658	5,183,416	5,627,255	5,343,435	5,407,071	4,114,490	3,599,299	4,110,140	52,897,589	4,408,135
2	BHE				259,014	255,954	241,780	216,707	250,832	250,108	293,867	304,254	308,704	238,555	250,963	264,894	3,135,632	261,303
4	CMP				1,428,622	1,401,608	1,320,141	1,183,150	1,419,192	1,389,328	1,598,002	1,599,651	1,604,426	1,326,342	1,382,391	1,527,230	17,180,083	1,431,673
6	NEP				5,510,344	5,367,135	5,132,475	4,586,944	6,454,677	7,028,884	7,707,244	7,376,371	7,415,825	5,142,677	5,079,413	5,753,513	72,555,502	6,046,299
7	NU				6,886,567	6,615,613	6,105,117	5,479,252	7,927,226	8,296,472	9,386,673	8,677,493	8,856,360	5,747,362	6,197,745	7,046,737	87,222,617	7,268,552
8	UI				673,518	654,718	616,254	577,671	793,371	922,248	1,018,517	935,281	946,311	610,120	624,164	692,664	9,064,837	755,404
9	VELCO/VT Transco				862,181	833,223	762,799	696,510	847,085	826,446	972,059	903,568	920,042	725,300	791,744	891,313	10,032,270	836,022
15	FGE				75,632	74,236	69,560	63,575	84,426	82,854	92,978	92,162	91,780	67,892	73,974	79,327	948,396	79,033

NETWORK LOAD VALUE (kW)

	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Total Annual Network Load	Average Monthly Network Load
Total Network Load (kW)	19,692,341	19,002,861	17,884,572	16,177,351	22,482,467	23,979,756	26,696,595	25,232,215	25,550,519	17,972,738	17,999,693	20,365,818	253,036,926	21,086,421

Local Network ID	Local Network Name	Network Load ID	Duns Number	Network Load Name	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Total Annual Network Load	Average Monthly Network Load
6	NEP	142	00-695-2626	Massachusetts Electric (NEMASS & Boston)	867,757	834,014	785,100	689,201	984,468	1,062,631	1,208,799	1,153,845	1,159,910	777,862	773,179	903,205	11,199,971	933,331
6	NEP	143	03-647-6141	Green Mountain Power (New Hampshire)	33,300	33,810	29,368	28,283	23,582	31,664	36,385	38,913	35,007	32,526	33,448	32,821	389,107	32,426
6	NEP	144	03-647-6141	Green Mountain Power (WCMASS)	24,398	19,054	15,710	10,100	9,708	10,709	11,444	11,577	11,711	10,150	13,959	20,147	168,667	14,056
6	NEP	145	XX-XXX-0001	NP MBTA - NEP (SEMASS)	99	63	67	85	2	2	2	2	2	1	23	34	382	32
6	NEP	146	XX-XXX-0001	NP MBTA - NEP (WCMASS)	114	128	125	100	66	50	53	56	58	77	81	79	987	82
6	NEP	147	XX-XXX-0001	NP MBTA - NEP (NEMASS & Boston)	6,075	5,774	6,015	3,886	3,621	3,617	3,632	4,154	4,280	3,987	4,628	5,243	54,912	4,576
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)	87	83	62	48	70	253	71	57	113	363	94	129	1,430	119
1	BE	152	00-799-8644	NP - Nantucket (R W)	23,950	21,506	21,158	12,953	18,675	29,297	38,355	34,562	33,404	22,787	19,907	25,541	302,095	25,175
1	BE	153	05-448-1341	N EA Bellingham	1,916	1,629	1,107	0	0	0	0	0	0	0	1,286	1,694	7,632	636
1	BE	154	02-606-6550	MATEP, LLC	16,783	16,373	21,558	17,425	18,742	13,295	13,246	16,072	16,417	20,913	19,053	10,466	200,343	16,695
6	NEP	155	02-825-5979	Somerset Power station service	896	896	736	10	20	516	0	528	546	540	612	678	5,978	498
6	NEP	156	78-508-7888	BG Dighton Power station service	0	0	443	313	0	0	0	0	0	0	0	594	1,350	113
7	NU	157	80-693-1007	Milford Power	0	0	0	0	0	0	0	0	0	2,160	0	0	2,160	180
15	FGE	158	00-695-4317	Fitchburg Gas & Electric Light Company	75,632	74,236	69,560	63,575	84,426	82,854	92,978	92,162	91,780	67,892	73,974	79,327	948,396	79,033
7	NU	159	02-825-5979	Devon Off-line Sta. Serv.Load	801	797	704	392	373	384	419	396	382	449	575	811	6,483	540
7	NU	160	02-825-5979	MIddletown Off-line Sta. Serv.Load	9,085	2,081	3,276	1,495	10,456	353	326	6,900	493	1,489	1,705	1,821	39,480	3,290

NETWORK LOAD VALUE (kW)

					Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Total Annual Network Load	Average Monthly Network Load
				Total Local Network Load (kW):	19,692,341	19,002,861	17,884,572	16,177,351	22,482,467	23,979,756	26,696,595	25,232,215	25,550,519	17,972,738	17,999,693	20,365,818	253,036,926	21,086,421
Local Network ID	**Local Network Name**																	
1	BE				3,996,463	3,800,374	3,636,446	3,373,542	4,705,658	5,183,416	5,627,255	5,343,435	5,407,071	4,114,490	3,599,299	4,110,140	52,897,589	4,408,135
2	BHE				259,014	255,954	241,780	216,707	250,832	250,108	293,867	304,254	308,704	238,555	250,963	264,894	3,135,632	261,303
4	CMP				1,428,622	1,401,608	1,320,141	1,183,150	1,419,192	1,389,328	1,598,002	1,599,651	1,604,426	1,326,342	1,382,391	1,527,230	17,180,083	1,431,673
6	NEP				5,510,344	5,367,135	5,132,475	4,586,944	6,454,677	7,028,884	7,707,244	7,376,371	7,415,825	5,142,677	5,079,413	5,753,513	72,555,502	6,046,299
7	NU				6,886,567	6,615,613	6,105,117	5,479,252	7,927,226	8,296,472	9,386,673	8,677,493	8,856,360	5,747,362	6,197,745	7,046,737	87,222,617	7,268,552
8	UI				673,518	654,718	616,254	577,671	793,371	922,248	1,018,517	935,281	946,311	610,120	624,164	692,664	9,064,837	755,404
9	VELCO/VT Transco				862,181	833,223	762,799	696,510	847,085	826,446	972,059	903,568	920,042	725,300	791,744	891,313	10,032,270	836,022
15	FGE				75,632	74,236	69,560	63,575	84,426	82,854	92,978	92,162	91,780	67,892	73,974	79,327	948,396	79,033

NETWORK LOAD VALUE (kW)

	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10		
Total Network Load (kW)	19,692,341	19,002,861	17,884,572	16,177,351	22,482,467	23,979,756	26,696,595	25,232,215	25,550,519	17,972,738	17,999,693	20,365,818	253,036,926	21,086,421

Local Network ID	Local Network Name	Network Load ID	Duns Number	Network Load Name	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Total Annual Network Load	Average Monthly Network Load
7	NU	161	02-825-5979	Montville Off-line Sta. Serv.Load	1,339	1,521	1,618	903	1,369	5	0	895	1,713	996	1,276	1,387	13,022	1,085
7	NU	162	02-825-5979	Norwalk Harbor Off-line Sta. Serv.Load	1,000	703	760	658	0	0	0	0	0	994	760	2,748	7,623	635
7	NU	163	04-042-2193	MP2 Offline Station Service Load	0	0	0	0	0	0	0	0	0	0	28,888	0	28,888	2,407
7	NU	164	04-042-2193	MP3 Offline Station Service Load	44,337	0	0	0	0	0	0	0	0	0	0	0	44,337	3,695
9	VELCO/VT Tr	165	02-813-4570	Town of Stowe Electric Dept.	13,616	14,505	8,782	6,808	8,561	9,783	12,187	11,245	11,095	8,180	17,085	18,495	140,342	11,695
7	NU	166	82-524-2444	Waterbury Generation Sta. Srv. Load	0	220	0	114	0	0	0	0	0	0	0	0	334	28
8	UI	168	05-448-1341	Bridgeport Energy-Station Service	0	3,000	0	0	0	0	0	0	0	0	0	3,450	6,450	538
6	NEP	169	01-821-3640	ANP Power Milford	302	302	216	173	0	0	0	0	0	0	518	821	2,332	194
6	NEP	170	82-893-7941	L'Energia Montgomery	576	490	403	547	0	0	0	0	0	0	346	432	2,794	233
7	NU	171	00-347-1322	Kleen Energy Station Service Load	200	1,044	0	0	0	0	0	0	0	710	1,537	1,749	5,240	437
7	NU	172	01-580-7673	GenConn Devon Units 15-18 offline s/s			0	0	457	764	274	0	0	255	597	987	3,334	278

Attachment 2

PTOs' Annual Transmission Revenue Requirement Calculations
Pursuant to Attachment F
Based on 2010 Actual Data, 2011 Forecasted Data and Annual True-up

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

🟨 Shading denotes an input

Submitted on: 18 May 2011

Revenue Requirements for (year): Calendar Year 2011

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 =	$1,055,140	(a)	$34,197,286	(f)
Total of Attachment F - Section J - Support Revenue	$0	(b)	$0	(g)
Total of Attachment F - Section K - Support Expense	$150,829	(c)	$0	(h)
Total of Attachment F - Section (L through O)	($24,595)	(d)	($766,122)	(i)
Sub Total - Sum (A through I) - J + K + (L through O)	$1,181,374	(e)=(a)-(b)+(c)+(d)	$33,431,164	(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	NA		$6,575,240	(k)
Annual True-up (per Attachment C to Attachment F Implementation Rule)	($17,431)	(l)	($706,694)	(m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)	$1,163,943	(n)=(e)+(l)	$39,299,710	(o)=(j)+(k)+(m)
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals, Forecasted Revenue Requirements, and True-ups (including interest).			$40,463,653	(p) = (n) + (o)

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2010
PRE-1997

🟨 Shading denotes an input

Line No.	I. INVESTMENT BASE	Attachment F Reference *Section:*	Total	Reference
1	Transmission Plant	(A)(1)(a)	6,428,129	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	104,487	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)		6,532,616	
5	Accumulated Depreciation	(A)(1)(d)	(754,886)	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	(678,666)	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)	(78,368)	Worksheet 3, line 15 column 5
9	Net Investment (Line 4+5+6+7+8)		5,020,696	
10	Prepayments	(A)(1)(h)	1,415	Worksheet 3, line 16 column 5
11	Materials & Supplies	(A)(1)(i)	302	Worksheet 3, line 17 column 5
12	Cash Working Capital	(A)(1)(j)	29,211	Worksheet 3, line 24 column 5
13	Total Investment Base (Line 9+10+11+12)		5,051,624	
II.	REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	790,133	Worksheet 2
15	Depreciation Expense	(B)	121,539	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)	(539)	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	58,623	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	2,525	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	(G)	41,624	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	41,235	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)	150,829	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)	(30,336)	from G/L
28	Transmission Rents Received from Electric Property	(O)	5,741	Exhibit: Transmission Rents
29	Total Revenue Requirements (Line 14 thru 28)		1,181,374	

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2010
POST-1996

🟨 Shading denotes an input

Line No.	I. INVESTMENT BASE	Attachment F Reference *Section:*	Post-96 (less NRI)	NRI	Total	Reference
1	Transmission Plant	(A)(1)(a)	58,102,929	142,132,418	200,235,347	from GL, Worksheet 3 line 1
2	General Plant	(A)(1)(b)	3,254,806	n/a	3,254,806	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)		61,357,735	142,132,418	203,490,153	
5	Accumulated Depreciation	(A)(1)(d)	(16,722,271)	(6,792,658)	(23,514,929)	from GL / Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	(11,373,796)	(9,766,848)	(21,140,644)	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)	(2,441,201)	n/a	(2,441,201)	Worksheet 3, line 15 column 5
9	Net Investment (Line 4+5+6+7+8)		30,820,467	125,572,912	156,393,379	
10	Prepayments	(A)(1)(h)	44,086	n/a	44,086	Worksheet 3, line 16 column 5
11	Materials & Supplies	(A)(1)(i)	9,406	n/a	9,406	Worksheet 3, line 17 column 5
12	Cash Working Capital	(A)(1)(j)	322,638	n/a	322,638	Worksheet 3, line 24 column 5
13	Total Investment Base (Line 9+10+11+12)		31,196,597	125,572,912	156,769,509	

	II. REVENUE REQUIREMENTS		Post-96 (less NRI)	NRI	Total	
14	Investment Return and Income Taxes	(A)	24,520,946	1,421,284	25,942,230	Worksheet 2
15	Depreciation Expense	(B)			3,785,964	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)			(16,786)	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)			1,826,120	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)			78,658	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	(G)			1,296,620	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)			1,284,480	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)			(944,953)	from G/L
28	Transmission Rents Received from Electric Property	(O)			178,831	Exhibit: Transmission Rents
29	Total Revenue Requirements (Line 14 thru 28)				33,431,164	

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2010
PRE-1997

🟨 Shading denotes an input

		CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	156,363,635	33.11%	7.31%	2.42%	
PREFERRED STOCK		399,300	0.08%	7.09%	0.01%	0.01%
COMMON EQUITY		315,523,107	66.81%	11.64%	7.78%	7.78%
TOTAL INVESTMENT RETURN	$	472,286,042	100.00%		10.21%	7.79%

Cost of Capital Rate=													
(a) Weighted Cost of Capital	=		0.1021										
(b) Federal Income Tax	=	(	R.O.E. +	(	PTF Inv. (Tax Credit	+	Eq. AFUDC of Deprec. Exp.)	/	PTF Inv. Base)	x	Federal Income Tax Rate	)	
		(	1							-	Federal Income Tax Rate	)	
	=	(	0.0779	+(	(539)	+	5,038)	/	5,051,624)	x	0.35	)	
		(	1							-	0.35	)	
	=		0.0424257										
(c) State Income Tax	=	(	R.O.E. +	(	PTF Inv. (Tax Credit	+	Eq. AFUDC of Deprec. Exp.)	/	PTF Inv. Base)	+	Federal Income Tax	)*	State Income Tax Rate
		(	1							-	State Income Tax Rate	)	
	=	(	0.0779	+(	(539)	+	5,038)	/	5,051,624)	+	0.0424257	)*	0.0893
		(	1							-	0.0893	)	
	=		0.0118860										
(a)+(b)+(c) Cost of Capital Rate	=		0.1564117										

		(PTF)	
INVESTMENT BASE	$	5,051,624	From Worksheet 1
x Cost of Capital Rate		0.1564117	
= Investment Return and Income Taxes		790,133	To Worksheet 1

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2010
POST-1996

🟨 Shading denotes an input

	CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 156,363,635	33.11%	7.31%	2.42%	
PREFERRED STOCK	399,300	0.08%	7.09%	0.01%	0.01%
COMMON EQUITY	315,523,107	66.81%	11.64%	7.78%	7.78%
TOTAL INVESTMENT RETURN	$ 472,286,042	100.00%		10.21%	7.79%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.1021

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

= (0.0779 +((16,786) + 156,924) / 156,769,509) x 0.35)
(1 - 0.35)

= 0.0424275

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)* State Income Tax Rate
(1 - State Income Tax Rate)

= (0.0779 +((16,786) + 156,924) / 156,769,509) + 0.0424275)* 0.0893
(1 - 0.0893)

= 0.0118865

(a)+(b)+(c) Cost of Capital Rate = 0.1564140

	(PTF)	
INVESTMENT BASE	$ 156,769,509	From Worksheet 1
x Cost of Capital Rate	0.1564140	
= Investment Return and Income Taxes	24,520,946	To Worksheet 1

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2010
POST-2003 (NRI)

🟨 Shading denotes an input

		CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	156,363,635	33.11%	0.00%	0.00%	
PREFERRED STOCK		399,300	0.08%	0.00%	0.00%	0.00%
COMMON EQUITY		315,523,107	66.81%	1.0%	0.67%	0.67%
TOTAL INVESTMENT RETURN	$	472,286,042	100.00%		0.67%	0.67%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0067

(b) Federal Income Tax

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

$$= \left(\frac{0.0067 \quad \text{x} \quad 0.35}{1 \quad - \quad 0.35}\right)$$

$$= 0.0036077$$

(c) State Income Tax

$$= \frac{(\text{R.O.E.} \quad + \quad \text{Federal Income Tax})^{*} \quad \text{State Income Tax Rate}}{(1 \quad - \quad \text{State Income Tax Rate})}$$

$$= \frac{(0.0067 \quad + \quad 0.0036077)^{*} \quad 0.0893}{(1 \quad - \quad 0.0893)}$$

$$= 0.0010107$$

(a)+(b)+(c) Cost of Capital Rate = 0.0113184

		(PTF)	
INVESTMENT BASE (NRI)	$	125,572,912	From Worksheet 1
x Cost of Capital Rate		0.0113184	
= Investment Return and Income Taxes		1,421,284	To Worksheet 1

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2010
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)
	Transmission Plant						
1	Transmission Plant					6,428,129	Line 1, Worksheet 5
2	General Plant	43,004,991	11.7505% (a)	5,053,301	2.0677%	104,487	Page 207.96g
3	Total (line 1+2)			5,053,301		6,532,616	
4	Transmission Plant Held for Future Use	0		0	2.0677%	0	Page 214
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	(34,579,905)		(34,579,905)	2.0677%	(715,009)	Page 219.25b
6	General Plant Accum.Depreciation	(16,412,697)	11.7505% (a)	(1,928,574)	2.0677%	(39,877)	Page 219.28b
7	Total (line 5+6)			(36,508,479)		(754,886)	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)			(34,585,363) (d)	2.0677%	(715,122)	Page 450.1 Footnote
9	Accumulated Deferred Taxes (190)			1,763,118 (e)	2.0677%	36,456	Page 234 Footnote
10	Total (line 8+9)			(32,822,245)		(678,666)	
11	Transmission loss on Reacquired Debt	0	49.2226% (c)	0	2.0677%	0	Page 111.81c
	Other Regulatory Assets						
							Page 232.23f - Page 278.1f + part of Page 122a (Column C)
12	FAS 106	(32,255,009)	11.7505% (a)	(3,790,125)	2.0677%	(78,368)	FAS 106 portion of AOCI
13	FAS 109	0	(f)	0	2.0677%	0	Excluded in Lines 8 & 9
14	Other Regulatory Liabilities (254.DK)	0	49.2226% (c)	0	2.0677%	0	n/a
15	Total (line 12+13+14)	(32,255,009)		(3,790,125)		(78,368)	
16	Transmission Prepayments	582,506	11.7505% (a)	68,447	2.0677%	1,415	Page 111.57c
17	Transmission Materials and Supplies	14,603		14,603	2.0677%	302	Page 227.8c
18	Cash Working Capital			302			
19	Operation & Maintenance Expense					41,624	Worksheet 1, Line 20
20	Administrative & General Expense					41,235	Worksheet 1, Line 21
21	Transmission Support Expense					150,829	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					233,688	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					29,211	

(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)
Annual Revenue Requirements of PTF Facilities
For Costs In 2010
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)
	Transmission Plant						
1	Transmission Plant			0		200,235,347	Line 1, Worksheet 5
2	General Plant	**43,004,991**	11.7505% (a)	5,053,301	64.4095%	3,254,806	Page 207.96g
3	Total (line 1+2)			5,053,301		203,490,153	
4	Transmission Plant Held for Future Use	0		0	64.4095%	0	Page 214
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	(34,579,905)		(34,579,905)	64.4095%	(22,272,744)	Page 219.25b
6	General Plant Accum.Depreciation	(16,412,697)	11.7505% (a)	(1,928,574)	64.4095%	(1,242,185)	Page 219.28b
7	Total (line 5+6)			(36,508,479)		(23,514,929)	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)			(34,585,363) (d)	64.4095%	(22,276,259)	Page 450.1
9	Accumulated Deferred Taxes (190)			1,763,118 (e)	64.4095%	1,135,615	Page 234 Footnote
10	Total (line 8+9)			(32,822,245)		(21,140,644)	
11	Transmission loss on Reacquired Debt	0	49.2226% (c)	0	64.4095%	0	Page 111.81c
	Other Regulatory Assets						
12	FAS 106	(32,255,009)	11.7505% (a)	(3,790,125)	64.4095%	(2,441,201)	Page 232.23f - Page 278.1f + part of Page 122a (Column C)
13	FAS 109	0	49.2226% (c)	0	64.4095%	0	Excluded in Lines 8 & 9
14	Other Regulatory Liabilities (254.DK)	0	49.2226% (c)	0	64.4095%	0	n/a
15	Total (line 12+13+14)	(32,255,009)		(3,790,125)		(2,441,201)	
16	Transmission Prepayments	582,506	11.7505% (a)	68,447	64.4095%	44,086	Page 111.57c
17	Transmission Materials and Supplies	14,603		14,603	64.4095%	9,406	Page 227.8c
18	Cash Working Capital						
19	Operation & Maintenance Expense					1,296,620	Worksheet 1, Line 20
20	Administrative & General Expense					1,284,480	Worksheet 1, Line 21
21	Transmission Support Expense					0	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					2,581,100	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					322,638	

(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)
Annual Revenue Requirements of PTF Facilities
For Costs In 2010
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)
	Depreciation Expense						
1	Transmission Depreciation	5,596,171		5,596,171	2.0677%	115,712	Page 336.7b
2	General Depreciation	2,398,081	11.7505% (a)	281,787	2.0677%	5,827	Page 336.10b
3	Total (line 1+2)			5,877,958		121,539	
4	Amortization of Loss on Reacquired Debt	0	49.2226% (c)	0	2.0677%	0	Page 117.64c
5	Amortization of Investment Tax Credits	52,945	49.2226% (c)	26,061	2.0677%	539	Page 266.8f
	Property Taxes						
6	*Transmission Property Taxes*	5,759,898	49.2226% (c)	2,835,172	2.0677%	58,623	Page 262-263, Note d
8	Line 6			2,835,172		58,623	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	(17,470,521)		(17,470,521)	2.0677%	(361,238)	Page 321.112b
10	Transmission of Electricity by Others - #565	(20,248,603)		(20,248,603)	2.0677%	(418,680)	Page 321.96b
11	Load Dispatching - #561 - 561.4	764,994		764,994	2.0677%	15,818	Page 321.84b-88b
12	**Station Expenses & Rents - #562 / #567					0	Page 321.93b & .98b
13	O&M less lines 10, 11 & 12	2,013,088		2,013,088	2.0677%	41,624	
	Transmission Administrative and General						
14	Administrative and General	15,560,131					Page 323.197b
15	*less Property Insurance (#924)*	*493,035*					*Page 323.185b*
16	*less Regulatory Commission Expenses (#928)*	*1,283,200*					*Page 350 (351.46[h+k])*
17	*less General Advertising Expense (#930.1)*	*0*					*Page 323.191b*
18	Subtotal [line 14 minus (15 thru 17)]	13,783,896	11.7505% (a)	1,619,677	2.0677%	33,490	
19	*PLUS Property Insurance alloc. using Plant Allocatior*	*493,035*	49.2226% *(c)*	242,685	2.0677%	5,018	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	*267,921*	49.2226% *(c)*	131,878	2.0677%	2,727	Exhibit: Reg Comission Expenses
21	*PLUS Trans. Related General Advertising Expense*	*0*	49.2226% *(c)*	0	2.0677%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*14,544,852*		*1,994,240*		*41,235*	
23	*Payroll Tax Expense*	*1,039,280*	11.7505% *(a)*	*122,121*	2.0677%	*2,525*	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	8,746	page 263.9i
FICA	1,004,983	page 263.6i
Medicare	0	
State Unemployment	25,551	page 263.13i
Total	1,039,280	*To Line 23*

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

Appropriate Property Taxes

BHE 2010	3,735,980	
BHE 2009	2,023,918	
Total	5,759,898	*To Line 6*

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2010
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)
	Depreciation Expense						
1	Transmission Depreciation	5,596,171		5,596,171	64.4095%	3,604,466	Page 336.7b
2	General Depreciation	2,398,081	11.7505% (a)	281,787	64.4095%	181,498	Page 336.10b
3	Total (line 1+2)			5,877,958		3,785,964	
4	Amortization of Loss on Reacquired Debt	0	49.2226% (c)	0	64.4095%	0	Page 117.64c
5	Amortization of Investment Tax Credits	52,945	49.2226% (c)	26,061	64.4095%	16,786	Page 266.8f
	Property Taxes						
6	*Transmission Property Taxes*	5,759,898	49.2226% (c)	2,835,172	64.4095%	1,826,120	Page 262-263 FN.1-2
8	Line 6			2,835,172		1,826,120	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	(17,470,521)		(17,470,521)	64.4095%	(11,252,675)	Page 321.112b
10	Transmission of Electricity by Others - #565	(20,248,603)		(20,248,603)	64.4095%	(13,042,024)	Page 321.96b
11	Load Dispatching - #561	764,994		764,994	64.4095%	492,729	Page 321.84b-88b
12	**Station Expenses & Rents - #562 / #567					0	Page 321.93b & .98b
13	O&M less lines 10, 11 & 12	2,013,088		2,013,088	64.4095%	1,296,620	
	Transmission Administrative and General						
14	Administrative and General	15,560,131					Page 323.197b
15	*less Property Insurance (#924)*	493,035					*Page 323.185b*
16	*less Regulatory Commission Expenses (#928)*	1,283,200					*Page 350 (351.46[h+k])*
17	*less General Advertising Expense (#930.1)*	0					*Page 323.191b*
18	Subtotal [line 14 minus (15 thru 17)	13,783,896	11.7505% (a)	1,619,677	64.4095%	1,043,226	
19	*PLUS Property Insurance alloc. using Plant Allocatior*	*493,035*	49.2226% *(c)*	242,685	64.4095%	156,312	
							Exhibit: Reg Comission Expenses
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	267,921	49.2226% *(c)*	131,878	64.4095%	84,942	
21	*PLUS Trans. Related General Advertising Expense*	0	49.2226% *(c)*	0	64.4095%	0	
22	Total A&G [line 18 plus (19 thru 21)	*14,544,852*		*1,994,240*		*1,284,480*	
23	*Payroll Tax Expense*	*1,039,280*	11.7505% *(a)*	*122,121*	64.4095%	*78,658*	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

Federal Unemployment	8,746	
FICA	1,004,983	
Medicare	0	
State Unemployment	25,551	
Total	1,039,280	*To Line 23*

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

Appropriate Property Taxes

BHE 2010	3,735,980	
BHE 2009	**2,023,918**	
Total	5,759,898	*To Line 6*

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2010
PRE-1997

🟨 Shading denotes an input

Line No.		Total	FERC Form 1 Reference
	PTF Transmission Plant Allocation Factor		
1	PTF Transmission Investment	6,428,129	ISO Catalog
2	Total Transmission Investment	310,878,489	Page 207.58g
3	Percent Allocation (Line 1/Line 2)	2.0677%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	1,256,731	Page 354.21b
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	1,256,731	
7	Total Wages and Salaries	13,996,381	Page 354.28b
8	Administrative and General Wages and Salaries	3,301,290	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)	10,695,091	
11	Percent Allocation (Line 6/Line 10)	11.7505%	
	Plant Allocation Factor		
12	Total Transmission Investment	310,878,489	Page 207.58g
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	5,053,301	*Worksheet 3, Line 2*
14	*= Revised Numerator (Line 12 + Line 13)*	315,931,790	
15	Total Plant in Service	641,843,209	Page 207.104g
16	Percent Allocation (Line 14 / Line 15)	49.2226%	

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2010
POST-1996

🟨 Shading denotes an input

Line No.		Total	FERC Form 1 Reference
	PTF Transmission Plant Allocation Factor		
1	PTF Transmission Investment	200,235,347	ISO Catalog
2	Total Transmission Investment	310,878,489	Page 207.58g
3	Percent Allocation (Line 1/Line 2)	64.4095%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	1,256,731	Page 354.21b
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	1,256,731	
7	Total Wages and Salaries	13,996,381	Page 354.28b
8	Administrative and General Wages and Salaries	3,301,290	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)	10,695,091	
11	Percent Allocation (Line 6/Line 10)	11.7505%	
	Plant Allocation Factor		
12	Total Transmission Investment	310,878,489	Page 207.58g
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	5,053,301	*Worksheet 3, Line 2*
14	*= Revised Numerator (Line 12 + Line 13)*	315,931,790	
15	Total Plant in Service	641,843,209	Page 207.104g
16	Percent Allocation (Line 14 / Line 15)	49.2226%	

Worksheet 6

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2010
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

Worksheet 7

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2010

🟨 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.

			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]		**6,972**
	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			
	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**			**43,526**
	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	332.1(g); [332(g) for CL&P]		**100,330**
	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	150,829

Amount by which Support Expense exceeds Support Revenues 150,829
(To Worksheet 3, Line 21, Column 5)

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2010
TRUE-UP

🟨 Shading denotes an input

Line No.	I. ANNUAL TRUE-UP	Period	Attachment F Reference Section:	PRE97	POST 1996	Reference
1	Prior Year (Billed) Revenue Requirement	06/10-05/11	Appendix C	$1,198,243	$34,115,068	Sub-Total ATRR plus FTRR (excludes ATU) "Summary", line 29 (before FTRR & ATU)
2	Prior Year (Actual) Revenue Requirement	TY 2010		$1,181,374	$33,431,164	
3	Under / (Over) Forecast (Lines 2 - 1)			($16,869)	($683,904)	
4	Annual True Up (ATU)	06/10-05/11		($16,869)	($683,904)	

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2010
FORECAST

🟨 Shading denotes an input

Line No.	I. FORECASTED TRANSMISSION REVENUE REQUIREMENTS	Period	Attachment F Reference *Section:*	POST-1996	Reference
1	Forecasted Transmission Plant Additions	2010	Appendix C	$38,500,000	
2	Carrying Charge Factor		Appendix C	17.08%	
3	Total Forecasted Revenue Requirements (Lines 1*2)			$6,575,240	

Line No.	II. CARRYING CHARGE FACTOR			
4	Investment Return and Income Taxes	(A)	$25,942,230	Worksheet 1 Post-96, line 14
5	Depreciation Expense	(B)	$3,785,964	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)	($16,786)	Worksheet 1 Post-96, line 17
8	Property Tax Expense	(E)	$1,826,120	Worksheet 1 Post-96, line 18
9	Payroll Tax Expense	(F)	$78,658	Worksheet 1 Post-96, line 19
10	Operation & Maintenance Expense	(G)	$1,296,620	Worksheet 1 Post-96, line 20
11	Administrative & General Expense	(H)	$1,284,480	Worksheet 1 Post-96, line 21
12	Total Expenses (Lines 4 thru 11)		$34,197,286	
13	PTF Transmission Plant	(A)(1)(a)	$200,235,347	Worksheet 1 Post-96, line 1
14	Carrying Charge Factor (Lines 12/13)		17.08%	

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2010
SUMMARY

Line No.	I. INVESTMENT BASE	Attachment F Reference *Section:*	Pre-97 Total	Post-96 Total	Reference
1	Transmission Plant	(A)(1)(a)	6,428,129	200,235,347	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	104,487	3,254,806	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)		6,532,616	203,490,153	
5	Accumulated Depreciation	(A)(1)(d)	(754,886)	(23,514,929)	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	(678,666)	(21,140,644)	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)	(78,368)	(2,441,201)	Worksheet 3, line 15 column 5
9	Net Investment (Line 4+5+6+7+8)		5,020,696	156,393,379	
10	Prepayments	(A)(1)(h)	1,415	44,086	Worksheet 3, line 16 column 5
11	Materials & Supplies	(A)(1)(i)	302	9,406	Worksheet 3, line 17 column 5
12	Cash Working Capital	(A)(1)(j)	29,211	322,638	Worksheet 3, line 24 column 5
13	Total Investment Base (Line 9+10+11+12)		5,051,624	156,769,509	
II.	REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	790,133	25,942,230	Worksheet 2
15	Depreciation Expense	(B)	121,539	3,785,964	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)	(539)	(16,786)	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	58,623	1,826,120	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	2,525	78,658	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	(G)	41,624	1,296,620	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	41,235	1,284,480	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)	150,829	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)	(30,336)	(944,953)	Worksheet 1, line 27
28	Transmission Rents Received from Electric Property	(O)	5,741	178,831	Worksheet 1, line 28
29	Total Revenue Requirements (Line 14 thru 28)		1,181,374	33,431,164	

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2010
INTEREST

🟨 Shading denotes an input

Pre 97 Under / (Over)	Post-96 Under/ (Over)
($16,869)	($683,904)

Initial Billing Period	Pre-97 Balance	Psot-96 Balance	FERC Monthly Interest Rate	Pre-97 Interest	Post-96 Interest
June-10	$ (16,869)	$ (683,904)	0.27%	$ (46)	$ (1,847)
July-10	$ (16,914)	$ (685,751)	0.28%	$ (47)	$ (1,920)
August-10	$ (16,914)	$ (685,751)	0.28%	$ (47)	$ (1,920)
September-10	$ (16,914)	$ (685,751)	0.27%	$ (46)	$ (1,852)
November-10	$ (17,055)	$ (691,442)	0.28%	$ (48)	$ (1,936)
November-10	$ (17,055)	$ (691,442)	0.27%	$ (46)	$ (1,867)
December-10	$ (17,055)	$ (691,442)	0.28%	$ (48)	$ (1,936)
January-11	$ (17,196)	$ (697,181)	0.28%	$ (48)	$ (1,952)
February-11	$ (17,196)	$ (697,181)	0.25%	$ (43)	$ (1,743)
March-11	$ (17,196)	$ (697,181)	0.28%	$ (48)	$ (1,952)
April-11	$ (17,336)	$ (702,828)	0.27%	$ (47)	$ (1,898)
May-11	$ (17,336)	$ (702,828)	0.28%	$ (49)	$ (1,968)
			Total Interest	$ (562)	$ (22,790)
			True-Up	($16,869)	($683,904)
			Total TU & Int	$ (17,431)	$ (706,694)

Exhibit: Regulatory Commission Expenses

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Regulatory Commission Expenses for 2010
Reconciliation of FERC Form 1 Data to Exhibit 5

	a	b		c
Line	Description	Expenses Booked		Reference
1	Expenses booked to Account 923 (directly related to reg proceedings)	$	38,808	Exhibit: Outside Legal Expenses (#923), line 13c
2	Regulatory commission expenses booked to Account 928	$	1,283,200	FF1 pg 350.46d
3	Line 2, directly attributable to Transmission			
a	Annual Federal Regulatory Assessment	$	173,635	
b	Order 890 Compliance			
c	2009 Transmission Rate Case	$	9,449	
d	General Transmission	$	35,498	
e	ROE ER04-157			
f	ISO-Withdrawal 2008-256	$	818	
g	CMP MPRP 2008-255	$	4,257	
h	First Wind Energy	$	5,456	
i	UPC Wind			
4	Account 928 directly related to Transmission	$	229,113	
5	2009 FERC Assessment	$	-	included in line 4, FF1 pg 351.2h
6	2010 pro-forma RTO Amortization Costs (June 1, 2010 through May 31, 2011)	$	-	Notes, Line 14c
7	6 months of 2009 pro-forma ommission of RTO Amortization costs	$	-	Notes, Line 13c / 2
8	**Total**	**$**	**267,921**	Line 1+4+5+6+7
9				
10	a	b		c
11	Notes			
12	1) 2008			
13	2) 2009			
14	3) 2010			

Exhibit: Transmission Rents

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Transmission Rents for 2010

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

Exhibit :Forecast Plant

Bangor Hydro-Electric Company

Line	Company	Project Name	RSP ID	(A) Estimated PTF Plant In-Service (in thousands)	(B) Annual Carrying Charge	(C)=(A)x(B) Forecasted PTF Revenue Requirement (in thousands)
1	BHE	Line 64	1116	$ 35,000	17.08%	$ 5,977
2	BHE	Orrington Shunt Capacitor Reconfiguration	1156	$ 3,500	17.08%	$ 598
3	**Total BHE**			**$ 38,500**		$ 6,575

Bangor Hydro-Electric Company
2010 PTF Plant Calculation
Additions, Retirements and Transfers
Summary By FERC Account

Line	a	b	c	d	e	f
1			**2009 Total PTF Plant**			
2	FERC		total	pre-97	post-96	post-03
3	350	Transmission Land	$ 12,861,343	$ 78,755	$ 3,402,551	$ 9,380,037
4	353	Substations	$ 24,659,646	$ 5,193,707	$ 2,153,872	$ 17,312,066
5	354	Towers and Fixtures	$ 9,292,923	$ 26,741	$ -	$ 9,266,182
6	355	Poles and Fixtures	$ 65,418,101	$ 518,084	$ 4,154,068	$ 60,745,948
7	356	Overhead Conductors	$ 61,430,330	$ 620,410	$ 3,626,185	$ 57,183,734
8	357	Underground Conduits	$ -	$ -	$ -	$ -
9	358	Underground Conductors	$ -	$ -	$ -	$ -
10	359	Roads and Trails	$ -	$ -	$ -	$ -
11			$ 173,662,342	$ 6,437,698	$ 13,336,677	$ 153,887,967
12						
13						
14			**2010 Incremental PTF**			
15	FERC		total	pre-97	post-96	post-03
16	350	Transmission Land	$ 346,502	$ -	$ (31,181)	$ 377,683
17	353	Substations	$ 36,493,277	$ 133,338	$ (10,147)	$ 36,370,086
18	354	Towers and Fixtures	$ 19,213	$ -	$ -	$ 19,213
19	355	Poles and Fixtures	$ 1,328,621	$ 75,635	$ (131,394)	$ 1,384,380
20	356	Overhead Conductors	$ (5,203,918)	$ (218,541)	$ (153,270)	$ (4,832,108)
21	357	Underground Conduits	$ 29	$ -	$ -	$ 29
22	358	Underground Conductors	$ 17,410	$ -	$ -	$ 17,410
23	359	Roads and Trails	$ -	$ -	$ -	$ -
24			$ 33,001,133	$ (9,569)	$ (325,991)	$ 33,336,693
25						
26						
27			**2010 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	$ 61,152,922	$ 5,327,045	$ 2,143,726	$ 53,682,152
31	354	Towers and Fixtures	$ 9,312,136	$ 26,741	$ -	$ 9,285,395
32	355	Poles and Fixtures	$ 66,746,722	$ 593,719	$ 4,022,675	$ 62,130,328
33	356	Overhead Conductors	$ 56,226,411	$ 401,869	$ 3,472,915	$ 52,351,627
34	357	Underground Conduits	$ 29	$ -	$ -	$ 29
35	358	Underground Conductors	$ 17,410	$ -	$ -	$ 17,410
36	359	Roads and Trails	$ -	$ -	$ -	$ -
37			$ 206,663,475	$ 6,428,129	$ 13,010,686	$ 187,224,660

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: 5/26/2011

Revenue Requirements for (year): 2010

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 =	179,154	(a)	2,142,485	(f)
Total of Attachment F - Section J - Support Revenue	0	(b)	0	(g)
Total of Attachment F - Section K - Support Expense	64,287	(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)	243,441	(e)=(a)-(b)+(c)+(d)	2,142,485	(j)=(f)-(g)+(h)+(i)
Forecasted Incremental Transmission Revenue Requirements			0	(m)
Annual True-up	6,541		213,991	(n)
Interest Charge on Annual True-up	321	(l)	10,509	(o)
Total = (e) + (j) + (k) + (l) + (m) + (n) + (o)	250,303	(p)	2,366,985	(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:			2,617,288	(r) = (p)+(q)

Braintree Electric Light Department

RNS Rate

Annual Revenue Requirements of pre-1997 & post-1996 PTF
for costs in 2009 06/10-05/11

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	Pre 1997	Post 1996	Reference
1	Transmission Plant	I (A)(1)(a)	1,703,903	20,283,972	Worksheet 3, line 1 column 5
2	General Plant	I (A)(1)(b)	10,948	130,331	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)		1,714,851	20,414,303	
5	Accumulated Depreciation	I (A)(1)(d)	722,546	8,601,460	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)		992,305	11,812,843	
10	Prepayments	I (A)(1)(h)	73	868	Worksheet 3, line 16 column 5
11	Materials & Supplies	I (A)(1)(i)	2,793	33,248	Worksheet 3, line 17 column 5
12	Cash Working Capital	I (A)(1)(j)	11,938	31,844	Worksheet 3, line 24 column 5
13	Total Investment Base (Line 9+11+12+13)		1,007,109	11,878,803	
II.	REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	I (A)	80,569	950,304	Worksheet 2
15	Depreciation Expense	I (B)	43,994	523,728	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)	15,671	185,826	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	I (F)	1,166	13,883	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	I (G)	10,661	126,915	Worksheet 4, line 13 column 5
21	Administrative & General Expense	I (H)	10,763	127,838	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)	74,076	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 Ta	I (N)	0	0	Txm related Acct 456
28	Transmission Rents Received from Electric Propert	I (O)	0	0	Txm related Acct 454-rent
29	Total Revenue Requirements (Line 14 thru 28)		236,900	1,928,494	
III.	CURRENT CALENDAR YEAR ESTIMATED INCREMENTAL REVENUE REQUIREMENT				
30	Carrying Charge Factor Base Revenue Requirement Numerator			2,091,318	
31	Post-2003 Enhanced Return Addition to Revenue Requirement			-	
32	Total Post-96 PTF Revenue Requirement			2,091,318	
33	Post-96 PTF Transmission Plant in Service			20,283,972	
34	Post-96 Carrying Charge Factor (Post-96 CCF)			9.5%	
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	

Braintree Electric Light Department
FERC Interest Calculation associated with Under / (Over)
True Up and Interest Calculation for 2010

1	2008 Actual Annual RR			243,441	2,142,485	Input Panel Subtotals
2	2008 Est. Transmission Revenue Requirements (as billed)	6/00-05/10	Appendix C	236,900	1,928,494	ATRR - Prior Year
3	True-up (Over)/Under (Line 1 - Line 2)			6,541	213,991	

	Overcollection/(Undercollection)
Pre'97	$6,541
Post'96	$213,991

Initial Billing Period	Pre 1997 Balance	Post 1996 Balance	FERC Monthly Interest Rate	Pre 1997 Interest	Post 1996 Interest
June 2007	$6,541	$213,991	0.56%	$37	$1,198
July 2007	6,578	215,189	0.45%	30	$968
August 2007	6,578	215,189	0.45%	30	$968
September 2007	6,578	215,189	0.44%	29	$947
October 2007	6,666	218,073	0.42%	28	$916
November 2007	6,666	218,073	0.41%	27	$894
December 2007	6,666	218,073	0.42%	28	$916
January 2008	6,749	220,799	0.38%	26	$839
February 2008	6,749	220,799	0.34%	23	$751
March 2008	6,749	220,799	0.38%	26	$839
April 2008	6,823	223,228	0.28%	19	$625
May 2008	6,823	223,228	0.29%	20	$647
		Total Interest		$321	$10,509
		True-Up		$6,541	$213,991
		Total TU & Int		**$6,862**	**$224,500**

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: 26-May-11

Revenue Requirements for (year): Calendar Year 2010

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

		Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	=	179,154	(a)		(f)
Total of Attachment F - Section J - Support Revenue		0	(b)	0	(g)
Total of Attachment F - Section K - Support Expense		64,287	(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)		243,441	(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:	243,441	(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: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)	243,441	(l)=(k)+(b)+(g)-(h)

▨ Shading denotes an input

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	**Braintree**	Reference
1	Transmission Plant	(A)(1)(a)	1,703,903	Worksheet 3a, L10
2	General Plant	(A)(1)(b)	14,695	Worksheet 3a, L11
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3a, L14
4	Total Plant (Lines 1+2+3)		1,718,598	
5	Accumulated Depreciation	(A)(1)(d)	685,593	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)		1,033,005	
10	Prepayments	(A)(1)(h)	98	Worksheet 3a, L34
11	Materials & Supplies	(A)(1)(i)	3,749	Worksheet 3a, L36
12	Cash Working Capital	(A)(1)(j)	10,812	Worksheet 3a, 44
13	Total Investment Base (Line 9+10+11+12)		1,047,664	
	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	83,813	Worksheet 2a, E56
15	Depreciation Expense	(B)	55,729	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)	15,816	Worksheet 4a, L21
19	Payroll Tax Expense	(F)	1,585	Worksheet 4a, L42
20	Operation & Maintenance Expense	(G)	8,233	Worksheet 4a, L29
21	Administrative & General Expense	(H)	13,978	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)	64,287	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)		243,441	
			179,154	

Braintree Electric Light Department

Annual Revenue Requirements - 2006
for costs in 2009

▨ 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

PTF Inv. Eq. AFUDC
(b) Federal Income Tax = (R.O.E. + ((Tax Credit + of Deprec. Exp.) / PTF Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

= (0.0000 +(0 + 0) / 1,047,664) x 0)
(1 - 0)

= 0.0000000

PTF Inv. Eq. AFUDC
(c) State Income Tax = (R.O.E. + ((Tax Credit + of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)* State Income Tax Rate
(1 - State Income Tax Rate)

= (0.0000 +(0 + 0) / 1,047,664) + 0.0000000)* 0
(1 - 0)

= 0.0000000

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

		(PTF)	
INVESTMENT BASE	$	1,047,664	From Worksheet 1
x Cost of Capital Rate		0.0800000	
= Investment Return and Income Taxes		83,813	To Worksheet 1

Braintree Electric Light Department

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	Mass DTE AR Reference for col (1)
	Transmission Plant						
1	Transmission Plant	$ 24,014,589		24,014,589		1,703,903	Worksheet 5, E12
2	General Plant	$ 15,414,816	1.3436% (a)	207,113	7.0953%	14,695	Page 8B line 29(g)
3	Total (line 1+2)			24,221,702		1,718,598	
4	Transmission Plant Held for Future Use	0		0	7.0953%	0	None known
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	9,597,083		9,597,083	7.0953%	680,942	Page 8A, line 31(g) less Page 16, line 31(g)
6	General Plant Accum.Depreciation	4,878,337	1.3436% (a)	65,545	7.0953%	4,651	Page 8B, line 29(g) less Page 17, line 29(g)
7	Total (line 5+6)			9,662,628		685,593	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	0	10.9483% (c)	0	7.0953%	0	None known
9	Accumulated Deferred Taxes (190)	0	10.9483% (c)	0	7.0953%	0	None known
10	Total (line 8+9)			0		0	
11	Transmission loss on Reacquired Debt	0	10.9483% (c)	0	7.0953%	0	None known
	Other Regulatory Assets						
12	FAS 106	0	1.3436% (a)	0	7.0953%	0	None known
13	FAS 109	0	10.9483% (c)	0	7.0953%	0	None known
14	Other Regulatory Liabilities (254.DK)	0	10.9483% (c)	0	7.0953%	0	
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments	102,649	1.3436% (a)	1,379	7.0953%	98	Page 10, Line 26 MA DTE
17	Transmission Materials and Supplies	3,932,409	1.3436%	52,836	7.0953%	3,749	Page 10, Line 24 MA DTE
18	Cash Working Capital						
19	Operation & Maintenance Expense					8,233	Worksheet 1, Line 20
20	Administrative & General Expense					13,978	Worksheet 1, Line 21
21	Transmission Support Expense					64,287	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					86,498	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					10,812	

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

Sheet: Worksheet 4

▨ 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	Transmission Depreciation	778,262		778,262	7.0953%	55,220	Page 16, line 31(d)
2	General Depreciation	533,604	1.3436% (a)	7,170	7.0953%	509	Page 17, line 29(d)
3	Total (line 1+2)			785,432		55,729	
4	Amortization of Loss on Reacquired Debt	0	10.9483% (c)	0	7.0953%	0	None known
5	Amortization of Investment Tax Credits	0	10.9483% (c)	0	7.0953%	0	None known
	Property Taxes *						
6	Transmission Property Taxes	1,813,444	0.109483	198,541	7.0953%	14,087	Page 21, line 33 (b)
7	General Property Taxes	1,813,444	1.3436% (a)	24,365	7.0953%	1,729	Page 21, line 33 (b)
8	Total (line 6+7)			222,906		15,816	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	116,971		116,971	0.070953	8,299	Page 40, line 50(b)
10	Transmission of Electricity by Others - #565	0		0	0.070953	0	Page 40, line 38(b)
11	Load Dispatching - #561	0		0	0.070953	0	Page 40, line 34(b)
12	**Station Expenses & Rents - #562 / #567	937		937	0.070953	66	Page 40, line 35(b) 40(b)
13	O&M less lines 10, 11 & 12	116,034		116,971	7.0953%	8,233	
	Transmission Administrative and General						
14	Administrative and General	8,466,266					Page 42, line 5(b)
15	*less Property Insurance (#924)*	*866,995*					Page 41, line 47(b)
16	*less Regulatory Commission Expenses (#928)*	0					Page 41, line 50(b)
17	*less General Advertising Expense (#930.1)*	*1,443*					*assumed none*
18	Subtotal [line 14 minus (15 thru 17)]	7,597,828	1.3436% (a)	102,084	7.0953%	7,243	
19	***PLUS*** *Property Insurance alloc. using Plant Allocatior*	*866,995*	*10.9483% (c)*	94,921	7.0953%	6,735	
20	***PLUS*** *Regulatory Comm. Exp. (FERC Assessments)*	*0*	*10.9483% (c)*	0	7.0953%	0	
21	***PLUS*** *Trans. Related General Advertising Expense*	*0*	*10.9483% (c)*	0	7.0953%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*8,464,823*		*197,005*		*13,978*	
23	*Payroll Tax Expense*	1,663,099	*1.3436% (a)*	*22,345*	*7.0953%*	*1,585*	Per company workpapers

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

Sheet: Worksheet 5

▨ Shading denotes an input

Line No.			Mass DTE AR Reference
	PTF Transmission Plant Allocation Factor	**Braintree**	
1	PTF Transmission Investment	1,703,903	Per Braintree Workpapers
2	Total Transmission Investment	24,014,589	Page 8A, line 31(g)
3	Percent Allocation (Line 1/Line 2)	7.0953%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	82,214	See BELD General Ledge
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 of 7
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	82,214	
7	Total Wages and Salaries	7,126,173	Page 42, line 24 (c)
8	Administrative and General Wages and Salaries	1,007,152	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)	6,119,021	
11	Percent Allocation (Line 6/Line 10)	1.3436%	
	Plant Allocation Factor		
12	Total Transmission Investment	24,014,589	Line 2
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	207,113	*Worksheet 3, Line 2*
14	*= Revised Numerator (Line 12 + Line 13)*	24,221,702	
15	Total Plant in Service	221,237,762	Page 8B, line 30 (g)
16	Percent Allocation (Line 14 / Line 15)	10.9483%	

Sheet: Worksheet 6 of 7

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

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.

			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]		$1,211
	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**			$8,980
	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			
NEP	**Moore 115 kV Substation**	332.1(g)		
	HQ Phase II - AC in MA	332.1(g); [332(g) for CL&P]		$21,758
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 394 line	332(g)		$2,742
	115 kV Read - Washington V148 line			
NU	**345 kV 363, 369 and 394 Seabrook lines**			$2,244
	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				$27,352
	Total =		0	64,287

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:	16-May-11
Revenue Requirements for (year):	Calendar Year 2010
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

		Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	=		(a)	2,142,485	(f)
Total of Attachment F - Section J - Support Revenue		0	(b)	0	(g)
Total of Attachment F - Section K - Support Expense			(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)	2,142,485	(j)

Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:	2,142,485	(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: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)	2,142,485	(l)=(k)+(b)+(g)-(h)

Calendar Year 2010

▨ Shading denotes an input

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	**Braintree**	Reference
1	Transmission Plant	(A)(1)(a)	21,557,662	Worksheet 3a, L10
2	General Plant	(A)(1)(b)	199,105	Worksheet 3a, L11
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3a, L14
4	Total Plant (Lines 1+2+3)		21,756,767	
5	Accumulated Depreciation	(A)(1)(d)	9,379,119	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)		12,377,648	
10	Prepayments	(A)(1)(h)	2,128	Worksheet 3a, L34
11	Materials & Supplies	(A)(1)(i)	50,385	Worksheet 3a, L36
12	Cash Working Capital	(A)(1)(j)	26,760	Worksheet 3a, 44
13	Total Investment Base (Line 9+10+11+12)		12,456,921	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	996,554	Worksheet 2a, E56
15	Depreciation Expense	(B)	705,074	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)	206,720	Worksheet 4a, L21
19	Payroll Tax Expense	(F)	20,059	Worksheet 4a, L42
20	Operation & Maintenance Expense	(G)	104,163	Worksheet 4a, L29
21	Administrative & General Expense	(H)	109,915	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)		2,142,485	

Braintree Electric Light Department
Annual Revenue Requirements - 2007
Calendar Year 2010

▨ 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

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

$$= \frac{(0.0000 + (0 + 0) / 12{,}456{,}921) \times 0)}{(1 - 0)}$$

$$= 0.0000000$$

(c) State Income Tax

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

$$= \frac{(0.0000 + (0 + 0) / 12{,}456{,}921) + 0.0000000)* 0}{(1 - 0)}$$

$$= 0.0000000$$

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

	(PTF)	
INVESTMENT BASE	$ 12,456,921	From Worksheet 1
x Cost of Capital Rate	0.0800000	
= Investment Return and Income Taxes	996,554	To Worksheet 1

Braintree Electric Light Department

Calendar Year 2010

▨ 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)
	Transmission Plant						
1	Transmission Plant	$ 24,014,589		24,014,589		21,557,662	Worksheet 5, E12
2	General Plant	$ 16,507,639	1.3436% (a)	221,797	89.7690%	199,105	Page 8B line 29(g)
3	Total (line 1+2)			24,236,386		21,756,767	
4	Transmission Plant Held for Future Use	0		0	89.7690%	0	None known
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	10,375,345		10,375,345	89.7690%	9,313,843	Page 8A, line 31(g) less Page 16, line 31(g)
6	General Plant Accum.Depreciation	5,411,941	1.3436% (a)	72,715	89.7690%	65,276	Page 8B, line 29(g) less Page 17, line 29(g)
7	Total (line 5+6)			10,448,060		9,379,119	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	0	11.3549% (c)	0	89.7690%	0	None known
9	Accumulated Deferred Taxes (190)	0	11.3549% (c)	0	89.7690%	0	None known
10	Total (line 8+9)			0		0	
11	Transmission loss on Reacquired Debt	0	11.3549% (c)	0	89.7690%	0	None known
	Other Regulatory Assets						
12	FAS 106	0	1.3436% (a)	0	89.7690%	0	None known
13	FAS 109	0	11.3549% (c)	0	89.7690%	0	None known
14	Other Regulatory Liabilities (254.DK)	0	11.3549% (c)	0	89.7690%	0	
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments	176,421	1.3436% (a)	2,370	89.7690%	2,128	Page 10, Line 26 MA DTE
17	Transmission Materials and Supplies	4,177,358	1.3436%	56,127	89.7690%	50,385	Page 10, Line 24 MA DTE
18	Cash Working Capital						
19	Operation & Maintenance Expense					104,163	Worksheet 1, Line 20
20	Administrative & General Expense					109,915	Worksheet 1, Line 21
21	Transmission Support Expense					0	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					214,078	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					26,760	

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

Sheet: Worksheet 4

Braintree Electric Light Department

Calendar Year 2010

PTF Revenue Requirements
Worksheet 4 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)
	Depreciation Expense						
1	Transmission Depreciation	778,262		778,262	89.7690%	698,638	Page 16, line 31(d)
2	General Depreciation	533,604	1.3436% (a)	7,170	89.7690%	6,436	Page 17, line 29(d)
3	Total (line 1+2)			785,432		705,074	
4	Amortization of Loss on Reacquired Debt	0	11.3549% (c)	0	89.7690%	0	None known
5	Amortization of Investment Tax Credits	0	11.3549% (c)	0	89.7690%	0	None known
	Property Taxes *						
6	Transmission Property Taxes	1,813,444	0.113549	205,915	89.7690%	184,848	Page 21, line 33 (b)
7	General Property Taxes	1,813,444	1.3436% (a)	24,365	89.7690%	21,872	Page 21, line 33 (b)
8	Total (line 6+7)			230,280		206,720	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	116,971		116,971	0.89769	105,004	Page 40, line 50(b)
10	Transmission of Electricity by Others - #565	0		0	0.89769	0	Page 40, line 38(b)
11	Load Dispatching - #561	0		0	0.89769	0	Page 40, line 34(b)
12	**Station Expenses & Rents - #562 / #567	937		937	0.89769	841	Page 40, line 35(b) 40(b)
13	O&M less lines 10, 11 & 12	116,034		116,971	89.7690%	104,163	
	Transmission Administrative and General						
14	Administrative and General	8,466,266					Page 42, line 5(b)
15	*less Property Insurance (#924)*	*86,995*					Page 41, line 47(b)
16	*less Regulatory Commission Expenses (#928)*	0					Page 41, line 50(b)
17	*less General Advertising Expense (#930.1)*	*1,443*					*assumed none*
18	Subtotal [line 14 minus (15 thru 17)]	8,377,828	1.3436% (a)	112,564	89.7690%	101,048	
19	***PLUS*** *Property Insurance alloc. using Plant Allocatior*	*86,995*	*11.3549% (c)*	9,878	89.7690%	8,867	
20	***PLUS*** *Regulatory Comm. Exp. (FERC Assessments)*	*0*	*11.3549% (c)*	0	89.7690%	0	
21	***PLUS*** *Trans. Related General Advertising Expense*	*0*	*11.3549% (c)*	0	89.7690%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*8,464,823*		*122,442*		*109,915*	
23	*Payroll Tax Expense*	1,663,098	*1.3436% (a)*	*22,345*	*89.7690%*	*20,059*	Per company workpapers

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

Sheet: Worksheet 5

▨ Shading denotes an input

Calendar Year 2010

Line No.			Mass DTE AR Reference
	PTF Transmission Plant Allocation Factor	**Braintree**	
1	PTF Transmission Investment	21,557,662	Per Braintree Workpapers
2	Total Transmission Investment	24,014,589	Page 8A, line 31(g)
3	Percent Allocation (Line 1/Line 2)	89.7690%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	82,214	See BELD General Ledge
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 of 7
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	82,214	
7	Total Wages and Salaries	7,126,173	Page 42, line 24 (c)
8	Administrative and General Wages and Salaries	1,007,152	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)	6,119,021	
11	Percent Allocation (Line 6/Line 10)	1.3436%	
	Plant Allocation Factor		
12	Total Transmission Investment	24,014,589	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)*	24,062,005	
15	Total Plant in Service	211,908,989	Page 8B, line 30 (g)
16	Percent Allocation (Line 14 / Line 15)	11.3549%	

Sheet: Worksheet 6 of 7

Affiliated Company Wages and Salaries

🟨 Shading denotes an input

Calendar Year 2010

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

Calendar Year 2010

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.

			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]		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 23, 2011

Revenue Requirements for (test year): Calendar Year 2010

Rates Effective for the period: June 1, 2011
through: May 31, 2012

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

		Pre-97 Revenue Requirements		**Post-96 Revenue Requirements**	
Total of Attachment F - Sections A through I	=	$ 17,847,055	(a)	$ 63,707,230	(f)
Total of Attachment F - Section J - Support Revenue		581,751	(b)	-	(g)
Total of Attachment F - Section K - Support Expense		738,625	(c)	-	(h)
Total of Attachment F - Section (L through O)		(767,588)	(d)	(1,378,588)	(i)
Sub Total - Sum (A through I) - J + K + (L through O)		17,236,341	(e)=(a)-(b)+(c)+(d)	62,328,642	(j)
Forecasted Transmission Revenue Requirements (per Appendix C to Attachment F Implementation Rule)		N/A		82,660,470	(k)
Annual True-up (per Appendix C to Attachment F Implementation Rule)		(1,610,066)	(l)	(1,682,144)	(m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)		**$ 15,626,275**	(n)=(e)+(l)	**$ 143,306,968**	(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)			**$ 158,933,243**	(p) = (n)+(o)	

CMP
Annual Revenue Requirements of PTF Facilities
2010

Line No.		Attachment F Reference Section:	PRE97	POST 1996	TOTAL	Reference
	I. INVESTMENT BASE					
1	Transmission Plant	(A)(1)(a)	$ 109,971,197	197,508,461	$ 307,479,658	Worksheet 1
2	General Plant	(A)(1)(b)	2,203,308	3,957,150	6,160,458	Worksheet 1
3	Plant Held For Future Use	(A)(1)(c)	861,600	1,547,437	2,409,037	Worksheet 1
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	Worksheet 1
6	Accumulated Deferred Income Taxes	(A)(1)(e)	10,892,586	19,563,124	30,455,710	Worksheet 1
7	Loss On Reacquired Debt	(A)(1)(f)	249,092	447,369	696,461	Worksheet 1
8	Other Regulatory Assets	(A)(1)(g)	192,991	346,612	539,603	Worksheet 1
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	Worksheet 1
11	Materials & Supplies	(A)(1)(i)	731,927	1,314,544	2,046,471	Worksheet 1
12	Cash Working Capital	(A)(1)(j)	519,794	898,333	1,418,127	Worksheet 1
13	MPRP CWIP	II (A)(1)(k)	-	182,322,304	182,322,304	Worksheet 1
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	Worksheet 1
16	Depreciation Expense	(B)	2,894,263	5,198,108	8,092,371	Worksheet 1
17	Amortization of Loss on Reacquired Debt	(C)	46,628	83,745	130,373	Worksheet 1
18	Investment Tax Credit	(D)	(46,870)	(84,179)	(131,049)	Worksheet 1
19	Property Tax Expense	(E)	1,155,258	2,074,848	3,230,106	Worksheet 1
20	Payroll Tax Expense	(F)	-	-	-	Worksheet 1
21	Operation & Maintenance Expense	(G)	3,180,784	5,712,700	8,893,484	Worksheet 1
22	Administrative & General Expense	(H)	820,691	1,473,964	2,294,655	Worksheet 1
23	Transmission Related Integrated Facilities Charge	(I)	-	-	-	Worksheet 1
24	Transmission Support Revenue	(J)	(581,751)	-	(581,751)	Worksheet 1
25	Transmission Support Expense	(K)	738,625	-	738,625	Worksheet 1
26	Transmission Related Expense from Generators	(L)	-	-	-	Worksheet 1
27	Transmission Related Taxes and Fees Charge	(M)	-	-	-	Worksheet 1
28	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(767,588)	(1,378,588)	(2,146,176)	Worksheet 1
29	Transmission Rents Received from Electric Property	(O)	-	-	-	Worksheet 1
30	Total RNS Revenue Requirements before Forecast, Annual True-up and Assoc. Interest (Line 15 thru 29)		$ 17,236,341	$ 62,328,642	$ 79,564,983	

CMP
Annual Revenue Requirements of PTF Facilities
2009

Line No.			Attachment F Reference Section:	PRE 97	POST 1996	TOTAL	Ref
	I.	INVESTMENT BASE					
1		Transmission Plant	(A)(1)(a)	$ 111,787,718	$ 176,158,940	$ 287,946,658	Worksheet 1
2		General Plant	(A)(1)(b)	3,251,403	5,123,672	8,375,075	Worksheet 1
3		Plant Held For Future Use	(A)(1)(c)	4,126,296	6,502,359	10,628,655	Worksheet 1
4		Total Plant (Lines 1+2+3)		119,165,417	187,784,971	306,950,388	
5		Accumulated Depreciation	(A)(1)(d)	41,209,100	64,938,722	106,147,822	Worksheet 1
6		Accumulated Deferred Income Taxes	(A)(1)(e)	8,980,064	14,151,095	23,131,159	Worksheet 1
7		Loss On Reacquired Debt	(A)(1)(f)	310,657	489,544	800,201	Worksheet 1
8		Other Regulatory Assets	(A)(1)(g)	323,726	510,138	833,864	Worksheet 1
9		Net Investment (Line 4-5-6+7+8)		69,610,636	109,694,836	179,305,472	
10		Prepayments	(A)(1)(h)	80,287	126,519	206,806	Worksheet 1
11		Materials & Supplies	(A)(1)(i)	687,588	1,083,525	1,771,113	Worksheet 1
12		Cash Working Capital	(A)(1)(j)	610,444	926,136	1,536,580	Worksheet 1
13		Total Investment Base (Line 9+10+11+12)		$ 70,988,955	$ 111,831,016	$ 182,819,971	Worksheet 1
	II.	REVENUE REQUIREMENTS					
14		Investment Return and Income Taxes	(A)	$ 10,637,524	$ 17,661,877	$ 28,299,401	Worksheet 1
15		Depreciation Expense	(B)	2,861,211	4,508,795	7,370,006	Worksheet 1
16		Amortization of Loss on Reacquired Debt	(C)	49,468	77,953	127,421	Worksheet 1
17		Investment Tax Credit	(D)	(50,619)	(79,767)	(130,386)	Worksheet 1
18		Property Tax Expense	(E)	1,010,677	1,592,660	2,603,337	Worksheet 1
19		Payroll Tax Expense	(F)	-	-	-	
20		Operation & Maintenance Expense	(G)	3,415,913	5,382,913	8,798,826	Worksheet 1
21		Administrative & General Expense	(H)	1,285,780	2,026,177	3,311,957	Worksheet 1
22		Transmission Related Integrated Facilities Charge	(I)	-	-	-	Worksheet 1
23		Transmission Support Revenue	(J)	(509,966)	-	(509,966)	Worksheet 1
24		Transmission Support Expense	(K)	691,822	-	691,822	Worksheet 1
25		Transmission Related Expense from Generators	(L)	-	-	-	
26		Transmission Related Taxes and Fees Charge	(M)	-	-	-	
27		Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(597,326)	(941,286)	(1,538,612)	Worksheet 1
28		Transmission Rents Received from Electric Property	(O)	-	-	-	
29		Total RNS Revenue Requirements before Forecast, Annual True-up and Assoc. Interest (Line 14 thru 28)		$ 18,794,484	$ 30,229,322	$ 49,023,806	
30		Forecasted PTF Revenue Requirements - 2010		-	33,727,217	33,727,217	
31		Total RNS Rev Req'ts subject to Annual True-up		$ 18,794,484	$ 63,956,539	$ 82,751,023	
32		PY true-up		506,717	3,122,169	3,628,886	
33		Total RNS-6/1/10-5/31/11		$ 19,301,201	$ 67,078,708	$ 86,379,909	

CMP

Transmission Revenue Requirements of PTF Facilities

2010 True-up

	I. APPENDIX C - ANNUAL TRUE-UP	Rate Year	PRE97	POST 1996	Total	Reference
1	ATRR for True-up = 2010 Actual	6/1/11-5/31/2012	$ 17,236,341	$ 62,328,642	$ 79,564,983	Summary 6-1-11_5-31-12, line 29
2	ATRR subject to True-up = '09 TY + '10 Forecast (as billed)	6/1/10-5/31/2012	$ 18,794,484	$ 63,956,539	$ 82,751,023	Summary 6-1-10_5-31-11, line 30
3	Annual True-up (Line 1 - Line 2)		$ (1,558,143)	$ (1,627,897)	$ (3,186,040)	

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

	Undercollection / (Overcollection)
PRE97	(1,558,143)
Post1996	(1,627,897)

Initial Billing Period	PRE97 Balance	POST 1996 Balance	FERC Monthly Interest Rate	PRE97 Interest	POST 1996 Interest	
June 2010	(1,558,143)	(1,627,897)	0.27%	$ (4,206.99)	$ (4,395.32)	
July 2010	(1,562,350)	(1,632,292)	0.28%	(4,374.58)	(4,570.42)	
August 2010	(1,562,350)	(1,632,292)	0.28%	(4,374.58)	(4,570.42)	
September 2010	(1,562,350)	(1,632,292)	0.27%	(4,218.34)	(4,407.19)	
October 2010	(1,575,317)	(1,645,840)	0.28%	(4,410.89)	(4,608.35)	
November 2010	(1,575,317)	(1,645,840)	0.27%	(4,253.36)	(4,443.77)	
December 2010	(1,575,317)	(1,645,840)	0.28%	(4,410.89)	(4,608.35)	
January 2011	(1,588,393)	(1,659,501)	0.28%	(4,447.50)	(4,646.60)	
February 2011	(1,588,393)	(1,659,501)	0.25%	(3,970.98)	(4,148.75)	
March 2011	(1,588,393)	(1,659,501)	0.28%	(4,447.50)	(4,646.60)	
April 2011	(1,601,259)	(1,672,943)	0.27%	(4,323.40)	(4,516.95)	
May 2011	(1,601,259)	(1,672,943)	0.28%	(4,483.52)	(4,684.24)	
		Total Interest		$ (51,923)	$ (54,247)	$ (106,170)
		True-Up		(1,558,143)	(1,627,897)	(3,186,040)
		Total TU & Int		$ (1,610,066)	$ (1,682,144)	$ (3,292,210)

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/10

Line No.	II.	INVESTMENT BASE	Attachment F Reference *Section:*		Reference
1		Transmission Plant	II (A)(1)(a)	$ 109,971,197	Worksheet 3, line 1 column 5
2		General Plant	II (A)(1)(b)	2,203,308	Worksheet 3, line 2 column 5
3		Plant Held For Future Use	II (A)(1)(c)	861,600	Worksheet 3, line 4 column 5
4		Total Plant (Lines 1+2+3)		113,036,105	
5		Accumulated Depreciation	II (A)(1)(d)	40,413,155	Worksheet 3, line 7 column 5
6		Accumulated Deferred Income Taxes	II (A)(1)(e)	10,892,586	Worksheet 3, line 10 column 5
7		Loss On Reacquired Debt	II (A)(1)(f)	249,092	Worksheet 3, line 11 column 5
8		Other Regulatory Asssets	II (A)(1)(g)	192,991	Worksheet 3, line 14 column 5
9		Net Investment (Line 4-5-6+7+8)		62,172,447	
10		Prepayments	II (A)(1)(h)	56,349	Worksheet 3, line 15 column 5
11		Materials & Supplies	II (A)(1)(i)	731,927	Worksheet 3, line 16 column 5
12		Cash Working Capital	II (A)(1)(j)	519,794	Worksheet 3, line 23 column 5
13		Total Investment Base (Line 9+10+11+12)		$ 63,480,517	
	II.	REVENUE REQUIREMENTS			
14		Investment Return and Income Taxes	II (A)	$ 9,796,301	Worksheet 2
15		Depreciation Expense	II (B)	2,894,263	Worksheet 4, line 3 column 5
16		Amortization of Loss on Reacquired Debt	II (C)	46,628	Worksheet 4, line 4 column 5
17		Investment Tax Credit	II (D)	(46,870)	Worksheet 4, line 5 column 5
18		Municipal Taxes	II (E)	1,155,258	Worksheet 4, line 8 column 5
19		Payroll Taxes	II (F)	-	Worksheet 4, line 9 column 5
20		Operation & Maintenance Expense	II (G)	3,180,784	Worksheet 4, line 14 column 5
21		Administrative & General Expense	II (H)	820,691	Worksheet 4, line 18 column 5
22		Transmission Related Integrated Facilities Charge	II (I)	-	
23		Transmission Support Revenue	II (J)	(581,751)	Worksheet 7, line 11 column a
24		Transmission Support Expense	II (K)	738,625	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)	(767,588)	Worksheet 20
28		Transmission Rents Received from Electric Property	II (O)	-	
29		Total Revenue Requirements (Line 14 thru 28)		$ 17,236,341	

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/10

see w/s 12 - capitalization		CAPITALIZATION	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	462,700,000	32.380%	6.648%	2.153%	
PREFERRED STOCK		2,660,500	0.186%	5.062%	0.009%	0.009%
COMMON EQUITY		963,604,143	67.434%	11.640%	7.849%	7.849%
TOTAL INVESTMENT RETURN	$	1,428,964,643	100.00%		10.011%	7.858%

Cost of Capital Rate=

(a) Weighted Cost of Capital	=		0.10011											
					PTF Inv.		Equity AFUDC							
(b) Federal Income Tax	=	(	R.O.E. +	(	Tax Credit -w/s 1	+	w/s 13	) /	PTF Inv. Base)		x	Federal Income Tax Rate	)	
		(	1								-	Federal Income Tax Rate	)	
	=	(	0.07858	+(	(46,870)	+	50,850	) /	63,480,517	)	x	0.35	)	
		(	1								-	0.35	)	
	=		0.0423461											
					PTF Inv.		Eq. AFUDC							
(c) State Income Tax	=	(	R.O.E. +	(	(Tax Credit	+	of Deprec. Exp.	) /	PTF Inv. Base)		+	Federal Income Tax	)*	State Income Tax Rate
		(	1								-	State Income Tax Rate	)	
	=	(	0.07858	+(	(46,870)	+	50,850	) /	63,480,517	)	+	0.0423461	)*	0.0893
		(	1								-	0.0893	)	
	=		0.0118637											
(a)+(b)+(c) **Cost of Capital Rate**	=		0.1543198											

		(PTF)
INVESTMENT BASE	$	63,480,517
x Cost of Capital Rate		0.1543198
= Investment Return and Income Taxes		9,796,301

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/10

Line No.		(1) Total	(2) Wage/Plant Allocation Factors		(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated		RNS Rate Worksheet or FERC Form 1 Reference for col (1) or (5)
	Transmission Plant								
1	Transmission Plant	-			-		109,971,197	(d)	w/s 5, line 1
2	General Plant	141,882,489	6.9433%	(a)	9,851,327	22.3656%	2,203,308		w/s 17, line 5
3	Total (line 1+2)				9,851,327		112,174,505		
4	Transmission Plant Held for Future Use	3,852,346			3,852,346	22.3656%	861,600		w/s 17, line 9
	Transmission Accumulated Depreciation								
5	Transmission Accum. Depreciation	(175,824,442)			(175,824,442)	22.3656%	(39,324,191)		w/s 17, line 4
6	General Plant Accum.Depreciation	(70,124,042)	6.9433%	(a)	(4,868,923)	22.3656%	(1,088,964)		w/s 17, line 7
7	Total (line 6+7)	(245,948,484)			(180,693,365)		(40,413,155)		
	Transmission Accumulated Deferred Taxes								
8	Accumulated Deferred Taxes (281-283)	(74,876,287)			(74,876,287)	22.3656%	(16,746,531)		See p. 450 notes for pages 274 & 276
9	Accumulated Deferred Taxes (190)	26,173,879			26,173,879	22.3656%	5,853,945		See p. 450 notes for page 234
10	Total (line 8+9)	(48,702,408)			(48,702,408)		(10,892,586)		
11	Unamortized loss on Reacquired Debt	3,799,598	29.3117%	(c)	1,113,726	22.3656%	249,092		Page 111.81c
	Other Regulatory Assets								
12	FAS 106	12,427,698	6.9433%	(a)	862,892				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)	12,427,698			862,892	22.3656%	192,991		
15	Transmission Prepayments	3,628,617	6.9433%	(a)	251,946	22.3656%	56,349		FF I 111.57c
16	Transmission Materials and Supplies	3,272,558			3,272,558	22.3656%	731,927		See note for page 227.11c on Page 450
17	Cash Working Capital								
18	Operation & Maintenance Expense						3,180,784		Worksheet 1, Line 21
19	Administrative & General Expense						820,691		Worksheet 1, Line 22
20	Net Transmission Support Expense						156,874		Worksheet 7, Line 13b
21	Subtotal (line 18+19+20)						4,158,349		
22							0.125		x 45 / 360
23	Total (line 21 * line 22)						519,794		

(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 12/31/10

Line No.		(1) Total	(2) Wage/Plant Allocation Factors		(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Worksheet or FERC Form 1 Reference for col (1)
	Depreciation Expense							
1	Transmission Depreciation	12,655,711			12,655,711	22.3656%	2,830,526	w/s 17, line 2
2	General Depreciation	4,104,391	6.9433%	(a)	284,980	22.3656%	63,737	w/s 17, line 6
3	Total (line 1+2)				12,940,691		2,894,263	
4	Amortization of Loss on Reacquired Debt	711,263	29.3117%	(c)	208,483	22.3656%	46,628	Page 117.64c
5	Amortization of Investment Tax Credits	(714,950)	29.3117%	(c)	(209,564)	22.3656%	(46,870)	Page 266.8f
	Property Taxes							
6	Transmission Property Taxes	5,165,335			5,165,335	22.3656%	1,155,258	See note for p. 262.14i on page 450.1
7	General Property Taxes	-	6.9433%	(a)	-	22.3656%	-	
8	Total (line 1+2)	5,165,335			5,165,335		1,155,258	
9	Payroll Taxes	-	-	(d)	-	-	-	
	Transmission Operation and Maintenance							
10	Operation and Maintenance	114,916,048						w/s 17, line 8
11	Transmission of Electricity by Others - #565	96,410,173						Page 321.96b/332/ws 11, line 17
12	Load Dispatching - #561 - 561.4	3,728,205						Page 321.84-88b
13	**Station Expenses & Rents - #562 / #567	555,901						ws 11, line 25
14	O&M - line 10 less lines 11, 12, & 13	14,221,769			14,221,769	22.3656%	3,180,784	
	Transmission Administrative and General							
15	A & G subject to Wage & Salaries Allocation Factor	37,797,850	6.9433%	(a)	2,624,418			w/s 9, line 28
16	A & G subject to Plant Allocation Factor	260,453	29.3117%	(c)	76,343			w/s 9, line 31
17	A & G directly assigned to transmission	968,672	100.00%		968,672			w/s 9, lines 14 & 17
18	A&G (line)	39,026,975			3,669,433	22.3656%	820,691	

(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
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/10

Line No.			RNS Rate Worksheet or FERC Form 1 Reference
	PTF Transmission Plant Allocation Factor		
		Pre 1997	
1	PTF Transmission Investment	109,971,197	w/s 15
2	Total Transmission Investment	491,698,019	w/s 15 & w/s 17 line 3
3	Percent Allocation (line 1/2)	22.3656%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	3,364,869	w/s 17, line 1
5	Affiliated Company Transmission Wages and Salaries	-	
6	Total Transmission Wages and Salaries (line 4+ 5)	3,364,869	
7	Total Wages and Salaries	52,898,584	Page 354.28b + line 5
8	Administrative and General Wages and Salaries	4,436,763	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)	48,461,821	
11	Percent Allocation (line 6/10)	6.9433%	
	Plant Allocation Factor		
12	Total Transmission Investment (excluding capital leases)	491,698,019	ws 5 line 2
13	Transmission Related General Plant	9,851,327	ws 3 line 2, col. 3
14	Total Transmission Related Plant	501,549,346	
15	Total Electric Plant in Service (excludes capital leases)	1,711,090,852	Page 207.104g (see 450 notes)
16	Percent Allocation (line 14/15)	29.3117%	

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/10

Affiliated Company Wages and Salaries

Line					
"Affiliated" Transmission Wages and Salaries			Transmission Wages by 3 digit FERC		
#560 - 573					
			560	687,857	
1	560	-	561-561.4	2,076,092	w/s 17 line 1b
			561.5-561.8	40,241	
2	562	-	562	546,641	
3	564	-	563	111,444	
4	566	-	564	358	
5	568	-	566	590,624	
			567	4,830	
6	569	-	568	162,420	
7	570	-	569	35,645	
8	571	-	570	957,046	
9	572	-	571	152,562	
10	573	-	572	73,345	
11 = 1 thru 10	Total Transmission	-	573	1,857	
				5,440,962	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 12/31/10

			CENTRAL MAINE POWER CO.		
	Participant	PTF Supporting Facilities	Revenues (a)	Expenses (b)	
1	NSTAR:	HQ Phase II - AC in MA		32,966	1
2	Central Maine Power:	345 kV Buxton-South Gorham 386 line	424,952		2
3		115 kV Wyman 164-167 lines	151,025		3
4		115 kV Maine Yankee transmission	-		4
5		50% of double steel towers # 30-46 (sec 375)	5,774		5
6					6
7	New England Power:	Chester SVC		211,632	7
8		HQ Phase II - AC in MA		494,027	8
9					9
10					10
11		Total =	581,751	738,625	11
12					12
13		Net Support (line 11b - 11a)		156,874	13

RNS Rate worksheet reference: col a - w/s 10, col b - w/s 11

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.

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/10

Summary of CMP System
Monthly Coincident Peaks

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Average
Network Load Customer	* Monthly Network Load (kW)	* Monthly Network Load (kW)	* Monthly Network Load (kW)	* Monthly Network Load (kW)	* Monthly Network Load (kW)	* Monthly Network Load (kW)	* Monthly Network Load (kW)	* Monthly Network Load (kW)	* Monthly Network Load (kW)	* Monthly Network Load (kW)	* Monthly Network Load (kW)	* Monthly Network Load (kW)	* Monthly Average Network Load (kW)
Central Maine Power	1,353,609	1,328,221	1,248,702	1,099,598	1,350,988	1,317,559	1,527,915	1,527,686	1,539,454	1,256,448	1,310,833	1,459,913	1,360,077
Fox Island (NP)	1,431	1,474	1,328	1,237	1,233	1,496	1,796	1,662	1,535	1,402	1,414	1,504	1,459
Kennebunk (NP)	16,626	16,057	15,230	12,410	16,322	16,497	19,788	18,983	18,926	14,148	14,767	16,847	16,383
Gates Formed Fiber (NP)	2,204	1,418	1,292	1,761	2,129	2,206	2,241	2,095	1,984	1,613	2,083	1,956	1,915
Madison Electric Works	5,532	5,505	4,893	17,835	4,661	4,101	5,232	5,483	5,497	4,443	4,680	5,500	6,114
FPL-Madison	46,840	47,880	45,300	48,730	41,790	47,460	41,030	43,630	36,880	48,270	48,570	41,510	44,824
Westbrook Energy Center	-	-	-	-	-	-	-	-	-	-	-	-	-
FPL Energy	2,380	1,053	3,396	1,579	2,069	9	-	112	150	18	44	-	901
Total	1,428,622	1,401,608	1,320,141	1,183,150	1,419,192	1,389,328	1,598,002	1,599,651	1,604,426	1,326,342	1,382,391	1,527,230	1,431,673
													99,795.60

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/10

	Acc't	Description	Amount	
1	920	Administrative and General Salaries	6,603,794	
2	921	Office Supplies and Expenses	2,761,740	
3	922	Less Administrative Expenses Transferred	(573,663)	
4	923	Outside Services	16,998,968	
5	924	Property Insurance	260,453	
6	925	Injuries and Damages	1,645,480	
7	926	Employee Pensions and Benefits	2,006,284	
8	928	Regulatory Commissions Expense	4,951,869	-
9	930.1	General Advertising	1,127,186	
10	930.2	Miscellaneous General Expense	6,038,781	
11	931	Rents	700,578	
12	935	Maintenance of General Plant	1,615,888	
13		Total Admin & Gen'l Exp.	44,137,358	Page 323.197b
14		FERC assessments - Transmission (directly assigned)	968,672	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)	968,672	FF1 page 350.d
17		State assessments - Transmission (directly assigned)	-	FF1 page 350.d
18		Total State Assessments	3,983,197	FF1 page 350.d
19	928	Total Regulatory Commissions Expense: (16+18) & from line 8	4,951,869	FF1 page 350.d, line 46
20		General Advertising - Transmission related	-	
21		Non-Transmission related General Advertising Exp.	1,127,186	
22	930.1	Total General Advertising Exp. (line 9)	1,127,186	
		Summary of Attachment F treatment of A&G		
23		Total A&G (line 13)	44,137,358	
24	924	less Property Insurance (line 5)	(260,453)	
25	928	less Regulatory Commissions Exp. (line 19)	(4,951,869)	
26	930.1	less Non-Trans. General Advertising Exp. (line 9)	(1,127,186)	
27	920-935	less EPRI Expenses	-	
28		A&G subject to Wages and Salaries Allocation Factor:	37,797,850	to worksheet 4, line 15, column 1
29		Property Insurance (line 5)	260,453	
30		Regulatory Commissions Exp. - FERC assessments (line 15)	-	
31		Total A&G subject to Plant Allocation Factor	260,453	to worksheet 4, line 16, column 1

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/10

	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)	($5,774)	-	($5,774)	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)	(151,025)	-	(151,025)	454
4	WF Wyman #4 Joint Owners	Section 386	ws 7, line 2, col. (a)	(424,952)	(609,750)	(1,034,702)	454
5	FPL			-	(179,314)	(179,314)	454
6	PSNH	Section 214 (from Kimball Rd substation)		-	-	-	454
7							
8		Total Support Revenues	ws 7, line 11, col. (a)	($581,751)	($789,064)	($1,370,815)	
9							
10		**Wheeling**					
11	Jurisdictional Sales			(136,401,181)	$ -	(136,401,181)	FFI p330 lines 11-15
12	RNS, TOUT, Sch 1			(83,300,893)	-	(83,300,893)	FFI p330 line 8
13	HVDC - Sch 20A-CMP				(4,996,475)	(4,996,475)	FFI p330 lines 2-6
14							
15		Total Wheeling Revenues		($219,702,074)	($4,996,475)	($224,698,549)	FF 1 p330 total col n.
16							
17							
18							
19							
20							
21	RNS			76,199,468	450 Notes for FF1 p.328, line 24		
22	SCH 1			4,955,249			
23	TOUT			2,146,176			
24	TOTAL		line 12, above	83,300,893			

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/10

	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	$ 32,966	-	$32,966	566
2	NEP	NEP Ph II, AC -O&M		195,502	-	$195,502	566
3		NEP Ph II, AC -RENTS		115,801	-	$115,801	567
4		NEP Ph II, AC -INTEREST		182,724	-	$182,724	431
5		NEP Ph II, AC -TOTAL	ws 7, line 8, col b	494,027	-	$494,027	
6		NHH- Chester SVC	ws 7, line 7, col b	211,632	-	$211,632	566
7							
8		Total Support Expenses	ws 7, line 11, col b	$ 738,625	-	$738,625	
9							
10		**Wheeling**					
11							
12	ISO-NE	Charges under the OATT		93,730,140		$93,730,140	lines 36 below
13	Bangor Hydro	Firm PTP Reservation for Energy Transferred to Herman Sta.		-	339,309	$339,309	565 FF1 pg 332, line 4
14	ISO-NE	Sch 1 - Part IV of ISO-NE Tariff		2,237,959		$2,237,959	line 37 below
15	PSNH	Bolt Hill		102,765		$102,765	565010 F1 pg 332, line 2
16							
17		Total Wheeling Expenses		$96,070,864	$339,309	$96,410,173	FERC Form 1 page 332
18							
19							
20							
21		SUMMARY BY FERC ACCOUNT:					
22		431				$ 182,724	
23		565				96,410,173	FERC Form 1 page 332
24		566				440,100	
25		567	(566+567 to ws 4, line 13)		555,901	115,801	
26						$ 97,148,798	
27							
28	RNS					$ 88,619,166	
29	Sch 1					2,255,299	
30	Sch 2 -CC					1,273,363	
31	Sch 2 -VAR Uplift					257,074	
32	Congestion Uplift					-	
33	Sch 16					716,708	
34	Load Response					523,390	
35	Sch 5-NESCO					85,140	
36	Total Charges ISO OATT					93,730,140	
37	ISO-NE Sch 1					2,237,959	450.1 Notes for FFI p.332.6
38	Total ISO Tariff					$ 95,968,099	565 FF1 pg 332, line 6.h.

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/10

		CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
MED-TERM NOTES		443,200,000	31.015%	6.697%		
POLLUTION CONTROL NOTES		19,500,000	1.365%	5.594%		
FAME		-	0.000%	0.000%		
MORTGAGE BONDS		-	0.000%	0.000%		
TOTAL LONG-TERM DEBT	page 112.21c	462,700,000	32.380%	6.648%	2.153%	
PREFERRED STOCK	page 112.3c	2,660,500	0.186%	5.062%	0.009%	0.009%
COMMON EQUITY	page 112.16c less line 3c	963,604,143	67.434%	11.640%	7.849%	7.849%
TOTAL INVESTMENT RETURN		1,428,964,643	100.00%		10.011%	7.858%

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/10

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	-	0.00%
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%
TOTALS	451,257,947	7,928,201	1.76%
Depreciation Exp from w/s 1			2,894,263
AFUDC adj to w/s 2			50,850

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/10

INVESTMENT-FERC A/C 101.1
(Not included in transmission plant)

G/L ACC'T	CAPITAL LEASES	BALANCE	RNS Rate w/s or FERC Form I Ref.
101101	Edison Drive	5,514,623	
101103	NEETCO HQDC	-	
101104	VETCO HQDC	-	
101105	NEP HQAC	2,620,620	
101106	NHH HQDC	2,002,243	
101107	NEH HQDC	3,306,101	
TOTAL CAPITAL LEASES		$ 13,443,587	Page 112.26+113.49

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/10

	PTF		Total PTF	Non-PTF	Total Transmission	
	pre 1997	post 1996				
TRANSMISSION LINES	77,390,939	69,326,156	146,717,095	73,695,228	220,412,322	
SUBSTATIONS	33,377,148	129,613,520	162,990,668	111,858,044	274,848,712	
TOTALS	110,768,087	198,939,676	309,707,763	185,553,272	495,261,035	
Less SCADA & RTUs directly assigned to Schedule 1	796,890	1,431,215	2,228,105	1,334,911	3,563,016	
Totals for RNS	109,971,197	197,508,461	307,479,658	184,218,361	491,698,019	w/s 17, line 3
PRE 1997 PTF - from above					$ 109,971,197	to w/s 5, line 1
POST 1996 PTF - from above					197,508,461	to Post 96 w/s 5, line 1
Total PRE 97 AND POST 96 PTF					$ 307,479,658	Total PTF Investment for RNS

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/10

PROPERTY DESCRIPTION	PROPERTY CLASSIFICATION	COST	ref	RESERVE	ref	DEPRECIATION	ref
Furniture & Equipment	General	266,008		131,948		10,450	
Structure Costs & Map Boards	General	3,750,352		1,546,214		91,884	
UPS	General	284,858		180,928		10,550	
EMS Hardware	General	1,466,475		1,041,609		162,925	
LMS	General	-		-		-	
EBCC	General	-		-		-	
Communication Equipment	General	815,265		606,383		59,677	
PC Equipment	General	-		30,034		-	
		6,582,957	w/s 17,5b	3,537,116	w/s 17,7b	335,486	w/s 17,6b
EMS Software	Intangibile	7,900,188		7,861,832		497,235	
S/S RTU's & Scada	Transmission	3,563,016	w/s 17,3b	1,135,688	w/s 17,4b	90,125	w/s 17,2b
Total Plant Directly Assigned to Schedule 1		18,046,161		12,534,636		922,846	

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/10

		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	5,440,961	(2,076,092)	-	3,364,869	1	WS 5, LINE 4
	TRANSMISSION DEPRECIATION EXP						
2	FERC FORM 1, PG. 336, LINE 7B	12,745,836	(90,125)	-	12,655,711	2	WS 4, LINE 1
	TOTAL TRANSMISSION PLANT						
3	FERC FORM 1, PG. 207, LINE 58G	464,815,805	(3,563,016)	30,445,230	491,698,019	3	WS 5, LINE 2
	TRANSMISSION PLANT DEPREC. RES.						
4	FERC FORM 1, PG 219, LINE 25c	176,960,130	(1,135,688)	-	175,824,442	4	WS 3, LINE 5
	TOTAL GENERAL PLANT						
5	FERC FORM 1, PG 207, LINE 99g	148,465,446	(6,582,957)	-	141,882,489	5	WS 3, LINE 2
	GENERAL DEPRECIATION EXPENSE						
6	FERC FORM 1, PG. 336, LINE 10b	4,439,877	(335,486)	-	4,104,391	6	WS 4, LINE 2
	GENERAL DEPRECIATION RESERVE						
7	FERC FORM 1, PG 219, LINE 28c	73,661,158	(3,537,116)	-	70,124,042	7	WS 3, LINE 6
	TRANSMISSION O&M						
8	FERC FORM 1, PG 321, LINE 112	114,916,048	-		114,916,048	8	WS 4, LINE 10
	TRANSMISSION PLANT HELD FOR FUTURE USE						
9	FF I, P 214, LINE 47 - (10+11)	34,297,576	-	(30,445,230)	3,852,346	9	WS 3, LINE 4

Lines 3 and 9: ($30,445,230) s/h/b recorded to acc't 105 but was improperly classified under acc't 106 (See FFI page 450 notes for pp 204-207 and p 214)

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/10

EHV PTF							
			UG	**NO OF**	**MILES**	**CKT**	
LINE	**KV**	**CONDUCTOR**	**OH**	**CKTS**	**PER CKT**	**MILES**	
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 12/31/10

Central Maine Power

Lower Voltage PTF

			UG	NO OF	MILES	CKT
LINE	**KV**	**CONDUCTOR**	**OH**	**CKTS**	**PER 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 IP - Kimball Rd (217)	115	1113 ACSR	OH	1	33.00	33.00
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 - Louden (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						958.38

TOTAL CENTRAL MAINE POWER COMPANY CKT. MILES						1,142.78

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/10

Through and Out Revenues				
	From Worksheet 10, line 23	2,146,176		
		-		
	Short-Term & Non-Firm T&O	2,146,176	See p.450 notes for p328,line 8	
	PTF BALANCE (see w/s 15)	% OF TOTAL	allocation of T/O Revenues	
PRE 1997 PTF	109,971,197	35.77%	767,588	
POST 96 PTF	197,508,461	64.23%	1,378,588	
TOTAL	307,479,658	100.00%	2,146,176	

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/10

			Attachment F Reference		Reference
Line No.	II.	INVESTMENT BASE	Section:		
1		Transmission Plant	II (A)(1)(a)	$ 197,508,461	Worksheet 3, line 1 column 5
2		General Plant	II (A)(1)(b)	3,957,150	Worksheet 3, line 2 column 5
3		Plant Held For Future Use	II (A)(1)(c)	1,547,437	Worksheet 3, line 4 column 5
4		Total Plant (Lines 1+2+3)		203,013,048	
5		Accumulated Depreciation	II (A)(1)(d)	72,582,176	Worksheet 3, line 7 column 5
6		Accumulated Deferred Income Taxes	II (A)(1)(e)	19,563,124	Worksheet 3, line 10 column 5
7		Loss On Reacquired Debt	II (A)(1)(f)	447,369	Worksheet 3, line 11 column 5
8		Other Regulatory Asssets	II (A)(1)(g)	346,612	Worksheet 3, line 14 column 5
9		Net Investment (Line 4-5-6+7+8)		111,661,729	
10					
11		Prepayments	II (A)(1)(h)	101,203	Worksheet 3, line 15 column 5
12		Materials & Supplies	II (A)(1)(i)	1,314,544	Worksheet 3, line 16 column 5
13		Cash Working Capital	II (A)(1)(j)	898,333	Worksheet 3, line 23 column 5
14		MPRP CWIP	II (A)(1)(k)	182,322,304	Worksheet 3, line 24 column 6
15		Total Investment Base (Line 9+11+12+13+14)		$ 296,298,113	
	II.	REVENUE REQUIREMENTS			
16		Investment Return and Income Taxes	II (A)	$ 49,248,044	Worksheet 2
17		Depreciation Expense	II (B)	5,198,108	Worksheet 4, line 3 column 5
18		Amortization of Loss on Reacquired Debt	II (C)	83,745	Worksheet 4, line 4 column 5
19		Investment Tax Credit	II (D)	(84,179)	Worksheet 4, line 5 column 5
20		Municipal Taxes	II (E)	2,074,848	Worksheet 4, line 8 column 5
21		Payroll Taxes	II (F)	-	Worksheet 4, line 9 column 5
22		Operation & Maintenance Expense	II (G)	5,712,700	Worksheet 4, line 14 column 5
23		Administrative & General Expense	II (H)	1,473,964	Worksheet 4, line 18 column 5
24		Transmission Related Integrated Facilities Charge	II (I)	-	
25		Transmission Support Revenue	II (J)	-	Worksheet 7, line 11 column a
26		Transmission Support Expense	II (K)	-	Worksheet 7, line 11 column b
27		Transmission Related Expense from Generators	II (L)	-	
28		Taxes and Fees	II (M)	-	
29		Revenues for TOUT Transmission Service	II (N)	(1,378,588)	W/S 13
30		Transmission Rents Received from Electric Property	II (O)	-	
31		Total Revenue Requirements (Line 16 thru 30)		$ 62,328,642	
		Forecasted Transmission Revenue Requirements - 2010		82,660,470	Worksheet 16, line 3
		Total - 2010 Actual + 2011 Forecasted		$ 144,989,112	

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/10

	see w/s 8 - capitalization		CAPITALIZATION		CAPITALIZATION RATIOS		COST OF CAPITAL		COST OF CAPITAL		EQUITY PORTION					
1	LONG-TERM DEBT	$	462,700,000		32.380%		6.648%		2.153%							
2	PREFERRED STOCK		2,660,500		0.186%		5.062%		0.009%		0.009%					
3	COMMON EQUITY		963,604,143		67.434%		11.640%		7.849%		7.849%					
4																
5	TOTAL INVESTMENT RETURN	$	1,428,964,643		100.00%				10.011%		7.858%				-7.86%	
6					67.434%		0.5%		0.337%		0.337%	0.569%	including FIT&SIT		0.58%	
7	New Inv Adder Calc. (100 bp)				67.434%		1.00%		0.674%		0.674%	1.139%	including FIT&SIT		-7.28%	taxes
8	MPRP New Inv Adder Calc. (125 bp)				67.434%		1.25%		0.843%		0.843%	1.424%	including FIT&SIT		8.692%	NI
9	**Cost of Capital Rate=**														0.009%	
10															2.15%	
11	(a) Weighted Cost of Capital	=	0.10011												3.58%	Interest
12																
13					PTF Inv.		Equity AFUDC									
14	(b) Federal Income Tax	= (	R.O.E. +	(	Tax Credit -w/s 1	+	w/s 13	) /	PTF Inv. Base)		x	Federal Income Tax Rate		)		
15		(	1								-	Federal Income Tax Rate		)		
16																
17		= (	0.07858	+(	(84,179)	+	91,326	) /	296,298,113	)	x	0.35		)		
18		(	1								-	0.35		)		
19																
20		=	0.0423253													
21																
22					PTF Inv.		Eq. AFUDC									
23	(c) State Income Tax	= (	R.O.E. +	(	(Tax Credit	+	of Deprec. Exp.	) /	PTF Inv. Base)		+	Federal Income Tax		)*	State Income Tax Rate	
24		(	1								-	State Income Tax Rate		)		
25																
26		= (	0.07858	+(	(84,179)	+	91,326	) /	296,298,113	)	+	0.0423253		)*	0.0893	
27		(	1								-	0.0893		)		
28																
29		=	0.0118579													
30																
31																
32																
33	(a)+(b)+(c) **Cost of Capital Rate**	=	0.1542932													
34																
35																
36																
37																
38			**Post 96 (PTF)**		**Post 2003 RSP ptf (Incremental Return Calc)**		**MPRP (Incremental Return Calc)**		**Investment Return & Taxes including Incremental Return**							
39			w/s 1 line 14		w/s 2a line 5		w/s 2a line 5									
40	INVESTMENT BASE	$	296,298,113		55,605,543		203,507,858									
41																
42	x Cost of Capital Rate		15.42932%		1.13860%		1.42409%									
43																
44	= Investment Return and Income Taxes		45,716,784		633,125		2,898,135		49,248,044	w/s 1 line 15						

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/10

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	$ 182,322,304	$ 182,322,304	$ -	$ -
2	MPRP PTF Investment	27,109,850	-	27,109,850	73,980,400
3	Depreciation Reserve	(984,758)	-	(984,758)	(5,755,935)
4	Accumulated Deferrred Income Taxes	(4,939,538)	-	(4,939,538)	(12,618,922)
5	INVESTMENT BASE	$ 203,507,858	$ 182,322,304	$ 21,185,554	$ 55,605,543
		w/s 2 line 40			w/s 2 line 40
6	Cost of Capital Rate - 11.64% ROE (w/s 2 line 33)		15.42932%		
7	Cost of Capital Rate - 1.25% bp ROE adder for MPRP (w/s 2 line 8)		1.42409%		
8	MPRP Cost of Capital Rate (MCOC)(6+7)		16.85341%		
9	MPRP CWIP - Base (5 x 6)		$ 28,131,092		
10	MPRP CWIP - Incremental (5 x 7)		2,596,434		
11	Investment Return and Income Taxes - MPRP CWIP (9+10)		$ 30,727,525		
12	Investment Return and Income Taxes - Total		$ 49,248,044	w/s 1, line 15	
13	Less Inv Return&Taxes- MPRP CWIP (11)		30,727,525		
14	Investment Return and Income Taxes - Post96 PTF		$ 18,520,519		
			w/s 16, line 10		

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/10

Line No.		(1) Total	(2) Wage/Plant Allocation Factors		(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated		RNS Rate Worksheet or FERC Form 1 Reference for col (1) or (5)
	Transmission Plant								
1	Transmission Plant	-			-		197,508,461	(d)	w/s 5, line 1
2	General Plant	141,882,489	6.9433%	(a)	9,851,327	40.1687%	3,957,150		w/s 12, line 5
3	Total (line 1+2)				9,851,327		201,465,611		
4	Transmission Plant Held for Future Use	3,852,346			3,852,346	40.1687%	1,547,437		w/s 17, line 9
	Transmission Accumulated Depreciation								
5	Transmission Accum. Depreciation	(175,824,442)			(175,824,442)	40.1687%	(70,626,393)		w/s 12, line 4
6	General Plant Accum.Depreciation	(70,124,042)	6.9433%	(a)	(4,868,923)	40.1687%	(1,955,783)		w/s 12, line 7
7	Total (line 6+7)	(245,948,484)			(180,693,365)		(72,582,176)		
	Transmission Accumulated Deferred Taxes								
8	Accumulated Deferred Taxes (281-283)	(74,876,287)			(74,876,287)	40.1687%	(30,076,831)		See p. 450 notes for pages 274 & 276
9	Accumulated Deferred Taxes (190)	26,173,879			26,173,879	40.1687%	10,513,707		See p. 450 notes for page 234
10	Total (line 8+9)	(48,702,408)			(48,702,408)		(19,563,124)		
11	Unamortized loss on Reacquired Debt	3,799,598	29.3117%	(c)	1,113,726	40.1687%	447,369		Page 111.81c
	Other Regulatory Assets								
12	FAS 106	12,427,698	6.9433%	(a)	862,892				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)	12,427,698			862,892	40.1687%	346,612		
15	Transmission Prepayments	3,628,617	6.9433%	(a)	251,946	40.1687%	101,203		FF I 111.57c
16	Transmission Materials and Supplies	3,272,558			3,272,558	40.1687%	1,314,544		See note for page 227.11c on Page 450
17	Cash Working Capital								
18	Operation & Maintenance Expense						5,712,700		Worksheet 1, Line 21
19	Administrative & General Expense						1,473,964		Worksheet 1, Line 22
20	Net Transmission Support Expense						-		
21	Subtotal (line 18+19+20)						7,186,664		
22							0.125		x 45 / 360
23	Total (line 21 * line 22)						898,333		
24	MPRP CWIP	182,322,304					182,322,304		Annual Report of Construction
	(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 12/31/10

Line No.		(1) Total	(2) Wage/Plant Allocation Factors		(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Worksheet or FERC Form 1 Reference for col (1)
	Depreciation Expense							
1	Transmission Depreciation	12,655,711			12,655,711	40.1687%	5,083,635	w/s 12, line 2
2	General Depreciation	4,104,391	6.9433%	(a)	284,980	40.1687%	114,473	w/s 12, line 6
3	Total (line 1+2)				12,940,691		5,198,108	
4	Amortization of Loss on Reacquired Debt	711,263	29.3117%	(c)	208,483	40.1687%	83,745	Page 117.64c
5	Amortization of Investment Tax Credits	(714,950)	29.3117%	(c)	(209,564)	40.1687%	(84,179)	Page 266.8f
	Property Taxes *							
6	Transmission Property Taxes	5,165,335			5,165,335	40.1687%	2,074,848	See note for p. 262.14i on page 450.1
7	General Property Taxes	-	6.9433%	(a)		40.1687%	-	
8	Total (line 1+2)	5,165,335			5,165,335		2,074,848	
9	Payroll Taxes	-	-	(d)	-	-	-	
	Transmission Operation and Maintenance							
10	Operation and Maintenance	114,916,048						w/s 12, line 8
11	Transmission of Electricity by Others - #565	96,410,173						Page 321.96b/332/pre97 ws 11, line 17
12	Load Dispatching - #561	3,728,205						Page 321.84-88b
13	**Station Expenses & Rents - #562 / #567	555,901						Pre 1997 ws 11, line 25
14	O&M - line 10 less lines 11, 12, & 13	14,221,769			14,221,769	40.1687%	5,712,700	
	Transmission Administrative and General							
15	A & G subject to Wage & Salaries Allocation Factor	37,797,850	6.9433%	(a)	2,624,418			w/s 7, line 28
16	A & G subject to Plant Allocation Factor	260,453	29.3117%	(c)	76,343			w/s 7, line 31
17	A & G directly assigned to transmission	968,672	100.00%		968,672			w/s 7, line 14
18	A&G (line 14+15)	39,026,975			3,669,433	40.1687%	1,473,964	

* 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 12/31/10

Line No.			RNS Rate Worksheet or FERC Form 1 Reference
	PTF Transmission Plant Allocation Factor		
		Post 1996	
1	PTF Transmission Investment	197,508,461	w/s 10
2	Total Transmission Investment	491,698,019	w/s 12, line 3 & w/s 10
3	Percent Allocation (line 1/2)	40.1687%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	3,364,869	w/s 12, line 1
5	Affiliated Company Transmission Wages and Salaries	-	
6	Total Transmission Wages and Salaries (line 4+ 5)	3,364,869	
7	Total Wages and Salaries	52,898,584	Page 354.28b + line 5
8	Administrative and General Wages and Salaries	4,436,763	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)	48,461,821	
11	Percent Allocation (line 6/10)	6.9433%	
	Plant Allocation Factor		
12	Total Transmission Investment (excluding capital leases)	491,698,019	ws 5 line 2
13	Transmission Related General Plant	9,851,327	ws 3 line 2
14	Total Transmission Related Plant	501,549,346	
15	Total Electric Plant in Service (excluding capital leases)	1,711,090,852	Page 207.104g (see 450 notes)
16	Percent Allocation (line 14/15)	29.3117%	

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/10

Affiliated Company Wages and Salaries

Line					
"Affiliated" Transmission Wages and Salaries			Transmission Wages by 3 digit FERC		
#560 - 573					
			560	687,857	
1	560	-	561-561.4	2,076,092	w/s 12 line 1b
2	562	-	561.5-561.8	40,241	
3	564	-	562	546,641	
4	566	-	563	111,444	
5	568	-	564	358	
6	569	-	566	590,624	
7	570	-	567	4,830	
8	571	-	568	162,420	
9	572	-	569	35,645	
10	573	-	570	957,046	
11 = 1 thru 10	Total Transmission	-	571	152,562	
			572	73,345	
			573	1,857	
				5,440,962	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 12/31/10

	Acc't	Description	Amount	
1	920	Administrative and General Salaries	6,603,794	
2	921	Office Supplies and Expenses	2,761,740	
3	922	Less Administrative Expenses Transferred	(573,663)	
4	923	Outside Services	16,998,968	
5	924	Property Insurance	260,453	
6	925	Injuries and Damages	1,645,480	
7	926	Employee Pensions and Benefits	2,006,284	
8	928	Regulatory Commissions Expense	4,951,869	
9	930.1	General Advertising	1,127,186	
10	930.2	Miscellaneous General Expense	6,038,781	
11	931	Rents	700,578	
12	935	Maintenance of General Plant	1,615,888	
13		Total Admin & Gen'l Exp.	44,137,358	Page 323.197b
14		FERC assessments - Transmission (directly assigned)	968,672	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)	968,672	FF1 page 350.d
17		State assessments - Transmission (directly assigned)	-	FF1 page 350.d
18		Total State Assessments	3,983,197	FF1 page 350.d
19	928	Total Regulatory Commissions Expense: (16+18) & from line 8	4,951,869	FF1 page 350.d, line 46
20		General Advertising - Transmission related	-	
21		Non-Transmission related General Advertising Exp.	1,127,186	
22	930.1	Total General Advertising Exp. (line 9)	1,127,186	
		Summary of Attachment F treatment of A&G		
23		Total A&G (line 13)	44,137,358	
24	924	less Property Insurance (line 5)	(260,453)	
25	928	less Regulatory Commissions Exp. (line 19)	(4,951,869)	
26	930.1	less Non-Trans. General Advertising Exp. (line 9)	(1,127,186)	
27	920-935	less EPRI Expenses	-	
28		A&G subject to Wages and Salaries Allocation Factor:	37,797,850	to worksheet 4, line 15, column 1
29		Property Insurance (line 5)	260,453	
30		Regulatory Commissions Exp. - FERC assessments (line 15)	-	
31		Total A&G subject to Plant Allocation Factor	260,453	to worksheet 4, line 16, column 1

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/10

		CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
MED-TERM NOTES		443,200,000	31.015%	6.697%		
POLLUTION CONTROL NOTES		19,500,000	1.365%	5.594%		
FAME		0	0.000%	0.000%		
MORTGAGE BONDS		0	0.000%	0.000%		
TOTAL LONG-TERM DEBT	page 112.21c	462,700,000	32.380%	6.648%	2.153%	
PREFERRED STOCK	page 112.3c	2,660,500	0.186%	5.062%	0.009%	0.009%
COMMON EQUITY	page 112.16c less line 3c	963,604,143	67.434%	11.640%	7.849%	7.849%
TOTAL INVESTMENT RETURN		1,428,964,643	100.00%		10.011%	7.858%

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/10

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	-	0.00%
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%
TOTALS	451,257,947	7,928,201	1.76%
Depreciation Exp from w/s 1			5,198,108
AFUDC adj to w/s 2			91,326

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/10

	PTF		Total PTF	Non-PTF	Total Transmission	
	pre 1997	post 1996				
TRANSMISSION LINES	77,390,939	69,326,156	146,717,095	73,695,228	220,412,322	
SUBSTATIONS	33,377,148	129,613,520	162,990,668	111,858,044	274,848,712	
TOTALS	110,768,087	198,939,676	309,707,763	185,553,272	495,261,035	
Balance per FERC Form 1; p. 207, line 53g	110,768,087	198,939,676	309,707,763	185,553,272	495,261,035	
Less SCADA & RTUs directly assigned to Schedule 1	796,890	1,431,215	2,228,105	1,334,911	3,563,016	
Totals for RNS	109,971,197	197,508,461	307,479,658	184,218,361	491,698,019	
PRE 1997 PTF - from above					$ 109,971,197	to Pre97 w/s 5, line 1
POST 1996 PTF - from above					197,508,461	to w/s 5, line 1
Total PRE 97 AND POST 96 PTF					$ 307,479,658	Total PTF Investment for RNS

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/10

PROPERTY DESCRIPTION	PROPERTY CLASSIFICATION	COST	ref	RESERVE	ref	DEPRECIATION	ref
Furniture & Equipment	General	266,008		131,948		10,450	
Structure Costs & Map Boards	General	3,750,352		1,546,214		91,884	
UPS	General	284,858		180,928		10,550	
EMS Hardware	General	1,466,475		1,041,609		162,925	
LMS	General	-		-		-	
EBCC	General	-		-		-	
Communication Equipment	General	815,265		606,383		59,677	
PC Equipment	General	-		30,034		-	
		6,582,957	w/s 17,5b	3,537,116	w/s 17,7b	335,486	w/s 17,6b
EMS Software	Intangibile	7,900,188		7,861,832		497,235	
S/S RTU's & Scada	Transmission	3,563,016	w/s 17,3b	1,135,688	w/s 17,4b	90,125	w/s 17,2b
Total Plant Directly Assigned to Schedule 1		18,046,161		12,534,636		922,846	

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/10

		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	5,440,961	(2,076,092)	-	3,364,869	1	WS 5, LINE 4
	TRANSMISSION DEPRECIATION EXP						
2	FERC FORM 1, PG. 336, LINE 7f	12,745,836	(90,125)	-	12,655,711	2	WS 4, LINE 1
	TOTAL TRANSMISSION PLANT						
3	FERC FORM 1, PG. 207, LINE 58g	464,815,805	(3,563,016)	30,445,230	491,698,019	3	WS 5, LINE 2
	TRANSMISSION PLANT DEPREC. RES.						
4	FERC FORM 1, PG 219, LINE 25c	176,960,130	(1,135,688)	-	175,824,442	4	WS 3, LINE 5
	TOTAL GENERAL PLANT						
5	FERC FORM 1, PG 207, LINE 99g	148,465,446	(6,582,957)	-	141,882,489	5	WS 3, LINE 2
	GENERAL DEPRECIATION EXPENSE						
6	FERC FORM 1, PG. 336, LINE 10f	4,439,877	(335,486)	-	4,104,391	6	WS 4, LINE 2
	GENERAL DEPRECIATION RESERVE						
7	FERC FORM 1, PG 219, LINE 28c	73,661,158	(3,537,116)	-	70,124,042	7	WS 3, LINE 6
	TRANSMISSION O&M						
8	FERC FORM 1, PG 321, LINE 112	114,916,048	-		114,916,048	8	WS 4, LINE 10
	TRANSMISSION PLANT HELD FOR FUTURE USE						
9	FF I, P 214, LINE 47 - (10+11)	34,297,576	-	(30,445,230)	3,852,346	9	WS 3, LINE 4

Lines 3 and 9: ($30,445,230) s/h/b recorded to acc't 105 but was improperly classified under acc't 106 (See FFI page 450 notes for pp 204-207 and p 214)

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/10

Through and Out Revenues

From Pre97 Worksheet 10, line 30		2,146,176	
		-	
Short-Term & Non-Firm T&O		2,146,176	See p.450 notes for p328,line 8

	PTF BALANCE (see w/s 15)	% OF TOTAL	allocation of T/O Revenues
PRE 1997 PTF	109,971,197	35.77%	767,588
POST 96 PTF	197,508,461	64.23%	1,378,588
TOTAL	307,479,658	100.00%	2,146,176

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/10

	Investment	2010 Activity				Investment
	as of 12/31/09	Additions	Retires	Transfers	Adjustments	as of 12/31/10
115kV Lines - Excluding Land						
60	$ 946,521	$ -	$ -	$ -	$ -	$ 946,521
61A	852,175	39,158	(9,885)	-	-	881,448
61	2,573,799	20,046	(26,906)	-	-	2,566,939
62	484,689	9,307	(296)	-	-	493,699
63	1,804,359	124,493	(8,619)	-	-	1,920,233
64	597,180	33,718	(2,867)	-	-	628,031
65	291,200	-	-	-	-	291,200
66	1,046,679	-	-	-	-	1,046,679
67	4,517,973	557,858	(1,927)	-	-	5,073,904
67A	-	-	(14,876)	-	556,593	541,717
68	4,316,974	-	-	-	-	4,316,974
69	2,998,299	-	-	-	-	2,998,299
75	1,108,877	-	-	-	-	1,108,877
80	1,987,324	47,402	(12,307)	-	-	2,022,420
81	977,727	11,741	(717)	-	-	988,751
83	1,437,396	8,863	(366)	-	-	1,445,893
84	1,478,961	64,120	(6,228)	-	-	1,536,853
86	4,103,928	53,316	(3,272)	-	-	4,153,973
87	287,518	18,018	(5,602)	-	-	299,935
88	1,204,897	-	-	-	-	1,204,897
89	473,459	131,163	(17,831)	-	-	586,791
140	2,147,014	-	-	-	-	2,147,014
160	597,609	-	-	-	-	597,609
161	1,191,547	-	-	-	-	1,191,547
162	656,828	2,253	-	-	-	659,081
163	7,230,280	(163,498)	-	-	-	7,066,782
164	2,354,016	1,373	-	-	-	2,355,390
165	822,862	33,003	(2,566)	-	-	853,300
166	1,203,155	109,348	(9,258)	-	-	1,303,245
167	1,124,808	7,533	(1,672)	-	-	1,130,669
169	501,035	-	-	-	-	501,035
197	5,314,323	1,739	-	-	-	5,316,063
200	968,173	-	(868)	-	-	967,305
201	1,505,421	-	-	-	-	1,505,421
202	315,157	-	-	-	-	315,157
203	1,020,665	12,768	(836)	-	-	1,032,597
204	957,721	-	-	-	-	957,721
205	388,523	-	(2,218)	-	-	386,305
207	1,798,053	-	-	-	-	1,798,053
208	635,814	35,302	(3,374)	-	-	667,742
209	868,872	-	-	-	-	868,872
210	1,828,178	-	-	-	-	1,828,178
211	8,521,805	(56)	-	-	-	8,521,749
212	1,656,113	85,882	(4,725)	-	-	1,737,270
213	2,357,014	-	(1,365)	-	-	2,355,649
214	1,670,056	-	-	-	-	1,670,056
217	3,553,887	-	-	-	-	3,553,887
219	8,533,147	-	-	-	-	8,533,147
220	4,622,264	707	-	-	-	4,622,971
221	-	-	-	-	437,177	437,177
223	1,842,786	-	-	-	-	1,842,786
224	1,796,606	-	-	-	-	1,796,606
225	2,133,106	-	-	-	-	2,133,106
226	1,885,886	5,878	(653)	-	-	1,891,111
228	39,450	-	-	-	-	39,450
229	1,024,860	208,804	(22,256)	-	-	1,211,408
231	760,031	-	-	-	-	760,031
232	229,977	-	-	-	-	229,977
233	231,717	-	-	-	-	231,717
234	677,554	-	-	-	-	677,554
237	1,414,590	-	-	-	-	1,414,590
238	637,671	-	-	-	-	637,671
242	-	-	-	-	123,296	123,296
250	1,786,003	11,098	(1,080)	-	-	1,796,021
275 URD	1,548,200	-	-	-	-	1,548,200
277	1,954,403	-	-	-	-	1,954,403
Total 115kV Lines	$ 115,797,117	$ 1,471,341	$ (162,571)	$ -	$ 1,117,066	$ 118,222,954

	Investment	2010 Activity				Investment
115kV Lines -Land	as of 12/31/09	Additions	Retires	Transfers	Adjustments	as of 12/31/10
60	99,483	-	-	-	-	99,483
61A	254,727	-	-	-	-	254,727
61	20,019	-	-	-	-	20,019
62	-	-	-	-	-	-
63	181,344	-	-	-	-	181,344
64	92,935	-	-	-	-	92,935
65	42,283	-	-	-	-	42,283
66	70,834	-	-	-	-	70,834
67	44,336	-	-	-	-	44,336
68	26,225	-	-	-	-	26,225
69	58,782	-	-	-	-	58,782
75	118,479	-	-	-	-	118,479
80	27,634	-	-	-	-	27,634
81	65,110	-	-	-	-	65,110
83	159,027	-	-	-	-	159,027
84	28,356	-	-	-	-	28,356
86	128,630	-	-	-	-	128,630
87	21,879	-	-	-	-	21,879
88	32,376	-	-	-	-	32,376
89	1,285		-	-	-	1,285
140	184,266	-	-	-	-	184,266
160	40,739		-	-	-	40,739
161	39,345		-	-	-	39,345
162	6,818	-	-	-	-	6,818
163	-	-	-	-	-	-
164	244,030		-	-	-	244,030
165	-	-	-	-	-	-
166	114,468	-	-	-	-	114,468
167	-	-	-	-	-	-
169	14,887	-	-	-	-	14,887
197	25,916	-	-	-	-	25,916
197 (Temp)	178,225	-	-	-	-	178,225
200	60,474	-	-	-	-	60,474
201	-	-	-	-	-	-
202	74,007	-	-	-	-	74,007
203	47,339	-	-	-	-	47,339
204	21,740	-	-	-	-	21,740
205	13,075	-	-	-	-	13,075
207	-	-	-	-	-	-
208	177,985	-	-	-	-	177,985
209	194,755		-	-	-	194,755
210	227,090	-	-	-	-	227,090
211	110,998	-	-	-	-	110,998
212	203,256	-	-	-	-	203,256
213	376,543	-	-	-	-	376,543
214	411,275	-	-	-	-	411,275
217	318,896		-	-	-	318,896
219	-	-	-	-	-	-

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/10

	Investment	2010 Activity				Investment
	as of 12/31/09	Additions	Retires	Transfers	Adjustments	as of 12/31/10
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
Total 115kV Land	$ 5,038,525	$ -	$ -	$ -	$ -	$ 5,038,525
	Investment	2010 Activity				Investment
345kV Lines(Including Land)	as of 12/31/09	Additions	Retires	Transfers	Adjustments	as of 12/31/10
374	3,155,722	-	-	-	-	3,155,722
374 (Temp) Reassign to Substations	-	-	-	-	-	-
375	4,986,735	11,353	-	-	-	4,998,088
377	4,218,878	-	-	-	-	4,218,878
378	869,515	-	(3,000)	-	-	866,515
385	3,368,470	-	-	-	-	3,368,470
386	3,651,517	320,653	(140,047)	-	-	3,832,122
391	3,007,853	8,095	(128)	-	-	3,015,820
Total 345kV Lines - EHV	23,258,690	340,101	(143,175)	-	-	23,455,615
Total PTF Lines	$ 144,094,332	$ 1,811,441	$ (305,746)	$ -	$ 1,117,066	$ 146,717,095
	Investment	2010 Activity				Investment
115kV Substations	as of 12/31/09	Additions	Retires	Transfers	Adjustments	as of 12/31/10
Augusta East	2,076,759	(129)	-	-	4,243	2,080,872
WF Wyman	963,360	(13,140)	-	-	0	950,221
Highland	938,286	-	(9,062)	-	(1,123)	928,101
Mason	3,420,307	94,038	(24,767)	-	43,172	3,532,750
Maxcy's	4,773,585	31,250	(4,485)	-	(29,564)	4,770,785
Topsham	-	-	-	-	-	-
Bath	1,633,624	50,024	(10,223)	-	18,231	1,691,656
Puddledock	156,334	-	-	-	-	156,334
Bowman St	694,451	-	-	-	396	694,847
Meadow Road	-	-	-	-	3,405	3,405
Newcastle	1,889,767	23,697	(80,008)	-	207,774	2,041,230
Crowley's	1,768,676	71,427	(9,110)	-	117,882	1,948,875
Gulf Island	2,861,215	9,296	(88,400)	2,153	1,160	2,785,424
Hotel Rd	534,555	833,531	(56,603)	-	(10,344)	1,301,140
Challenger Drive	153,976	1,136	-	-	-	155,112
Kimball Rd	4,795,146	-	(2,775)	-	17,999	4,810,370
Lewiston Lower	703,563	740	(2,995)	-	945	702,253
Livermore Falls	1,810,589	-	(2,639)	-	-	1,807,950
Lovell	-	-	-	-	-	-
Norway	23,706	-	-	-	13	23,719
Surowiec	2,701,328	-	-	-	3,958	2,705,287
Norway Switch	45,083	-	-	-	-	45,083
Raymond	1,459,130	-	-	-	-	1,459,130
Rumford	1,839,039	(641,280)	(5,941)	-	(629,862)	561,957
Riley	511,666	1,182,622	(30,877)	-	89,851	1,753,262
Woodstock	5,558,245	-	(92,455)	-	(148,841)	5,316,948
Rumford IP	1,147,673	5,481,129	(121,009)	-	11,894	6,519,687
Cape	-	-	-	-	237,422	237,422
Elm Street	-	-	-	-	75,831	75,831
Louden	4,764,954	22,704	(9,707)	-	663	4,778,614
Moshers	2,186,287	-	-	-	0	2,186,287
Mussey	405,192	-	-	-	-	405,192
West Kennebunk	327,668	-	-	-	-	327,668
Pleasant Hill	971,422	-	(15)	-	(1,740)	969,667
Prides Corner	-	-	-	-	-	-
Maguire Rd	12,062,037	281	-	-	371,297	12,433,615
Quaker Hill	1,180,884	-	-	-	(4,032)	1,176,851
Cape	574,641	-	-	-	-	574,641
Fore River	4,375,052	-	-	-	4,659	4,379,712
West Buxton	340,456	-	-	-	-	340,456
Sewall St	558,154	-	-	-	-	558,154
Spring St	1,969,939	-	-	-	(0)	1,969,939
Three Rivers	-	-	-	-	56,647	56,647
Biddeford Ind. Park	-	-	-	-	103,841	103,841
Sanford	1,922,560	-	-	-	(112,657)	1,809,903
South Gorham	4,080,940	599,326	(780,968)	-	965,539	4,864,838
Red Brook	331,907	3,303	(2,592)	-	261	332,879
Westbrook	1,724,288	-	(9,211)	-	40,239	1,755,317
Lincolnville	305,121	-	-	-	(668)	304,453
Bucksport	2,357,977	7,719	(1,891)	-	(193)	2,363,612
Detroit	1,386,922	1,898,894	(213,861)	-	(277,464)	2,794,491
Sappi (Hinckley)	-	-	-	-	-	-
Lakewood	-	-	-	-	166,546	166,546
Searsport	-	-	-	-	2,247	2,247
Sturtevant	142,527	-	-	-	-	142,527
Winslow	1,792,190	-	-	-	(28,822)	1,763,368
Heywood Road	-	-	-	-	6,820,403	6,820,403
Wyman	1,984,546	8,676	(166,480)	-	(253,844)	1,572,898
Belfast	-	-	-	-	3,965	3,965
Total 115kV	88,205,726	9,665,243	(1,726,072)	2,153	7,871,328	104,018,379
	Investment	2010 Activity				Investment
345kV	as of 12/31/09	Additions	Retires	Transfers	Adjustments	as of 12/31/10
Mason	$ 1,273,415	$ -	$ -	$ -	$ -	$ 1,273,415
Maxcy's	4,737,120	41,737	-	-	-	4,778,857
Maine Yankee	4,209,020	-	-	(19,183)	-	4,189,838
Surowiec	4,561,593	(2,911)	-	-	-	4,558,682
Buxton	16,954,298	63,438	-	-	-	17,017,735
South Gorham	25,584,911	1,749,641	-	(499,094)	318,303	27,153,762
Total 345kV	$ 57,320,357	$ 1,851,904	$ -	$ (518,276)	$ 318,303	$ 58,972,289
Total Substations	$ 145,526,084	$ 11,517,148	$ (1,726,072)	$ (516,123)	$ 8,189,632	$ 162,990,668
Total PTF	$ 289,620,416	$ 13,328,589	$ (2,031,818)	$ (516,123)	$ 9,306,698	$ 309,707,763
PTF portion of SCADA & RTU Investment Directly Assigned to Schedule 1 (see w/s 15)						(2,228,105)
Total PTF for Attachment F						$ 307,479,658

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/10

▨ Shading denotes an input

Line No.	FORECASTED TRANSMISSION REVENUE REQUIREMENTS (FTRR)	Forecast Period	Attachment F Reference	Amount	Reference
			Section:		
1	Forecasted Rev Req'ts for FTPA			$ 10,070,374	line 6 below
2	Forecasted Rev Req'ts for FCWIP			72,590,096	line 9 below
3	Forecasted Transmission Revenue Requirements (Lines 1 + 2)			$ 82,660,470	
4	Forecasted Transmission Plant Additions (FTPA)	2011	Appendix C iv	$ 60,309,335	Worksheet 17
5	Carrying Charge Factor (CCF)		Appendix C vi	16.70%	line 14 below
6	Forecasted Rev Req'ts for FTPA (Lines 1*2)			$ 10,070,374	
7	Forcasted MPRP CWIP (FCWIP)		Appendix C v	$ 430,714,589	Annual Report of Construction Costs
8	MPRP Cost of Capital Rate (MCOC)		Appendix C vii	16.85%	line 23 below
9	Forecasted Rev Req'ts for FCWIP (Lines 4*5)			$ 72,590,096	
	DERIVATION OF CARRYING CHARGE FACTOR (CCF)				
10	Investment Return and Income Taxes		(A)	$ 18,520,519	Worksheet 2a, line 14
11	Depreciation Expense		(B)	5,198,108	Worksheet 1, line 17
12	Amortization of Loss on Reacquired Debt		(C)	83,745	Worksheet 1, line 18
13	Investment Tax Credit		(D)	(84,179)	Worksheet 1, line 19
14	Property Tax Expense		(E)	2,074,848	Worksheet 1, line 20
15	Payroll Tax Expense		(F)	-	Worksheet 1, line 21
16	Operation & Maintenance Expense		(G)	5,712,700	Worksheet 1, line 22
17	Administrative & General Expense		(H)	1,473,964	Worksheet 1, line 23
18	Total Expenses (Lines 10 thru 17)			$ 32,979,705	
19	PTF Transmission Plant		(A)(1)(a)	$ 197,508,461	Worksheet 1, line 1
20	Carrying Charge Factor (Lines 18/19)			16.70%	
	DERIVATION OF MPRP COST OF CAPITAL RATE (MCOC)				
21	Cost of Capital Rate - 11.64% ROE			15.42932%	Worksheet 2, line 33
22	Cost of Capital Rate - 1.25% bp ROE adder for MPRP			1.42409%	Worksheet 2, line 8
23	MPRP Cost of Capital Rate (MCOC) (Lines 21 + 22)			16.85341%	

Annual Report of Construction Costs
For FERC Informational Filings

MAINE POWER
RELIABILITY PROGRAM
A CENTRAL MAINE POWER COMPANY PROGRAM

Local Filing - June 30, 2011

Regional Filing - July 29, 2011

CENTRAL MAINE
POWER

Burns & McDonnell
SINCE 1898

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Page No.

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PART I – SUMMARY OF CONSTRUCTION COSTS FOR FERC INFORMATIONAL FILINGS

Summary of MPRP Costs for the June 30th & 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 2010

   Another MPRP project component is the Lewiston Loop. This component was not included in the CPCN for MPRP that was approved by the MPUC on June 10, 2010. CMP has filed a separate CPCN application for the Lewiston Loop. 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.**

   CMP estimates the year end MPRP CWIP balance will be $430,714,589 for PTF facilities. CMP estimates the non-PTF balance to be $1,160,596 by the end of 2011.

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 estimated in-service costs per year for MPRP by PTF and Non-PTF excluding distribution costs estimated at $7,864,795.

Year	PTF ($000)	Non-PTF ($000)
2009	$ 22,435	$ 0
2010	$ 4,674	$ 709
2011	$ 47,087	$ 916
2012	$ 345,990	$ 10,675
2013	$ 367,890	$ 6,177
2014	$ 570,830	$ 4,225
2015	$ 25,294	$ 1,368
Total	**$1,384,200**	**$ 24,070**

The total estimated cost for components that are permitted, or will receive permits in the near future, is $1,416,135,000. 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 resources, and the realignment of Program escalation, contingency and reserve to account for Program duration and 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 $88,554,000 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 remains $1,504,689,000 with a modest amount of contingency used to fund construction, environmental access and controls.

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

Attachment 2 provides project cost summaries of the total project costs and costs by project element. Attachment 3 provides project cost estimate updated sheets by project element.

* * * * *

ATTACHEMENT 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 12/31/2009	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
CWIP													
So Gorham CWIP Additions	8,680.45	21.70	52,885.13	695.93	314,684.82	469,574.39	(50,033.38)	567,190.93	91,381.73	415,337.69	608,656.44	1,894,798.48	1,081,749.20
So Gorham CWIP to Move to In-Service in 2010	875,578.39	(82,580.70)	1,224,152.90	45,238.05	1,615,859.48	244,719.58							
MPRP CWIP (No So Gorham)								1,393.99	18,184.00	23,626,454.61	3,083,724.64	78,260,034.46	72,517,046.73
Cumulative Monthly CWIP Balance	**884,258.84**	**614,282.67**	**1,891,320.70**	**1,937,254.68**	**3,867,798.98**	**4,248,043.48**	**796,509.04**	**1,365,093.96**	**1,474,659.69**	**25,516,451.99**	**29,208,833.07**	**109,363,666.01**	**182,962,461.94**
In-Service													
Transfer from CWIP to In-Service 2010		187,417.17				334,049.47	3,401,501.06						
In-Service	22,435,778.01	2,480,555.32	(909,872.52)	44,739.46	(951,370.61)	107,266.49	(150,408.03)	414,225.95	8,565.02	17,952.16	92,931.60	955,517.62	(649,975.45)
Cumulative In-Service	**22,435,778.01**	**25,103,750.50**	**24,193,877.98**	**24,238,617.44**	**23,287,246.83**	**23,728,562.79**	**26,979,655.82**	**27,393,881.77**	**27,402,446.79**	**27,420,398.95**	**27,513,330.55**	**28,468,848.17**	**27,818,872.72**

ATTACHEMENT 2 – PROJECT COST SUMMARIES BY PROJECT ELEMENT

FIGURE 1 – MPRP COMBINED PROJECTS
(INCLUDES ALL PROJECTS)

COMBINED PACKAGE PROJECT COST ESTIMATE & SCHEDULE SHEET

Transmission Owner:	**Central Maine Power**	**RSP Project #:**	**Various**
Project Name:	**Maine Power Reliability Program**	**Date:**	**6/29/2011**
Estimate Grade:	**D (Construction)**		

1. Project Scope Summary

Central Maine Power is in the process of modernizing its 40 year-old bulk power transmission system by investing an estimated $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.

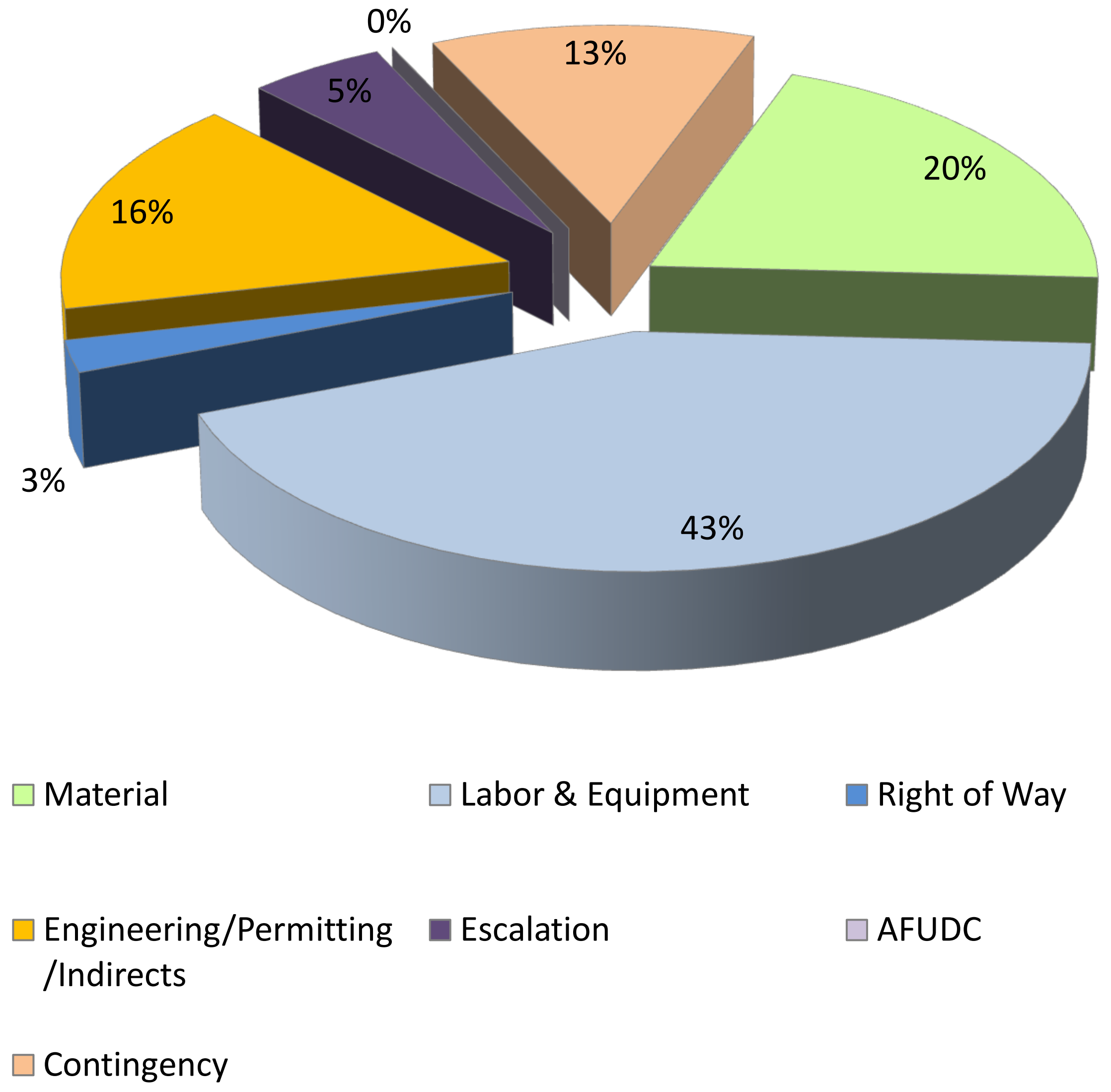
2. Project Cost Summary

Prior Estimated Cost:

2.1. Project Cost Summary

	PTF	Non-PTF*	**Total**
Material	$ 297,018	$ 8,018	$ 305,036
Labor & Equipment	$ 634,862	$ 17,138	$ 652,000
Right of Way	$ 34,642	$ 935	$ 35,577
Engineering/Permitting /Indirects	$ 236,381	$ 6,381	$ 242,762
Escalation	$ 77,744	$ 2,099	$ 79,843
AFUDC	$ 222	$ -	$ 222
Contingency	$ 184,274	$ 4,975	$ 189,248
Total Project Cost	**$ 1,465,143**	**$ 39,546**	**$ 1,504,689**

*Distribution costs in thousands carried in Non-PTF are estimated at $7,865



2.2 Detailed Cost Summary By Project Element

	Material	Labor & Equip.	Right of Way	Indirects	Escalation	AFUDC	Contingency	**Total**
2.2.1 New 345KV Lines	$ 108,105	$ 231,070	$ 12,609	$ 86,035	$ 28,296	$ -	$ 67,070	**$ 533,185**
2.2.2 New 115KV Lines	$ 39,015	$ 83,393	$ 4,550	$ 31,050	$ 10,212	$ -	$ 24,205	**$ 192,426**
2.2.3 New 345KV Substations	$ 53,236	$ 113,790	$ 6,209	$ 42,368	$ 13,934	$ -	$ 33,028	**$ 262,565**
2.2.4 New 115KV Substations	$ 9,144	$ 19,545	$ 1,067	$ 7,277	$ 2,393	$ -	$ 5,673	**$ 45,099**
2.2.5 345 KV Substations Expansions/Modifications	$ 17,596	$ 37,611	$ 2,052	$ 14,004	$ 4,606	$ 145	$ 10,917	**$ 86,931**
2.2.6 115 KV Substations Expansions/Modifications	$ 3,913	$ 8,365	$ 456	$ 3,114	$ 1,024	$ 77	$ 2,428	**$ 19,378**
2.2.7 Lines Rerates, Relocations, Rebuilds	$ 74,026	$ 158,228	$ 8,634	$ 58,914	$ 19,376	$ -	$ 45,927	**$ 365,104**
Total	**$ 305,036**	**$ 652,000**	**$ 35,577**	**$ 242,762**	**$ 79,843**	**$ 222**	**$ 189,248**	**$ 1,504,689**

Note: Values in thousands expressed in 2008 dollars.

FIGURE 2 – MPRP SETTLEMENT PROJECTS

SETTLEMENT PACKAGE PROJECT COST ESTIMATE & SCHEDULE SHEET

Transmission Owner: Central Maine Power
RSP Project #: Various
Project Name: Maine Power Reliability Program
Date: 6/29/2011
Estimate Grade: D (Construction)

1. Project Scope Summary

Central Maine Power is in the process of modernizing its 40 year-old bulk power transmission system by investing an estimated $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.

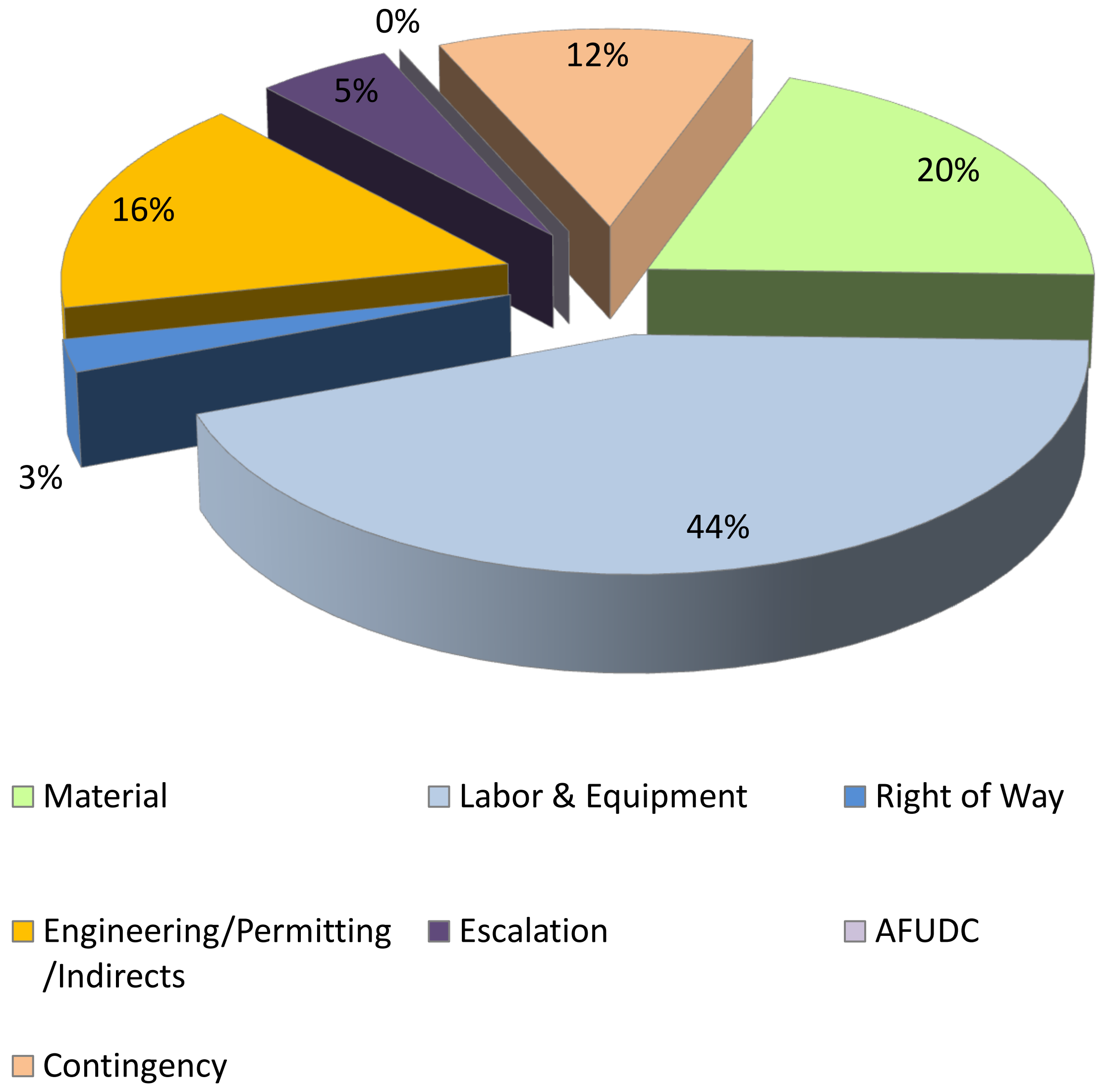
2. Project Cost Summary

Prior Estimated Cost:

2.1. Project Cost Summary $/1000

	PTF	Non-PTF*	Total
Material	$ 274,831	$ 6,242	$ 281,073
Labor & Equipment	$ 608,648	$ 13,825	$ 622,472
Right of Way	$ 33,245	$ 755	$ 34,000
Engineering/Permitting /Indirects	$ 224,995	$ 5,111	$ 230,105
Escalation	$ 72,612	$ 1,649	$ 74,261
AFUDC	$ 134	$ -	$ 134
Contingency	$ 170,223	$ 3,866	$ 174,089
Total Project Cost	**$ 1,384,686**	**$ 31,449**	**$ 1,416,135**

*Distribution costs in thousands carried in Non-PTF are estimated at $7,865



2.2 Detailed Cost Summary By Project Element $/1000

	Material	Labor & Equip.	Right of Way	Indirects	Escalation	AFUDC	Contingency	Total
2.2.1 New 345KV Lines	$ 99,613	$ 220,605	$ 12,050	$ 81,550	$ 26,318	$ -	$ 61,697	**$ 501,832**
2.2.2 New 115KV Lines	$ 35,950	$ 79,616	$ 4,349	$ 29,431	$ 9,498	$ -	$ 22,267	**$ 181,111**
2.2.3 New 345KV Substations	$ 49,054	$ 108,636	$ 5,934	$ 40,159	$ 12,960	$ -	$ 30,383	**$ 247,126**
2.2.4 New 115KV Substations	$ 8,426	$ 18,660	$ 1,019	$ 6,898	$ 2,226	$ -	$ 5,219	**$ 42,448**
2.2.5 345 KV Substations Expansions/Modifications	$ 16,214	$ 35,908	$ 1,961	$ 13,274	$ 4,284	$ 88	$ 10,042	**$ 81,770**
2.2.6 115 KV Substations Expansions/Modifications	$ 3,606	$ 7,986	$ 436	$ 2,952	$ 953	$ 46	$ 2,233	**$ 18,213**
2.2.7 Lines Rerates, Relocations, Rebuilds	$ 68,211	$ 151,062	$ 8,251	$ 55,842	$ 18,022	$ -	$ 42,248	**$ 343,635**
Total	**$ 281,073**	**$ 622,472**	**$ 34,000**	**$ 230,105**	**$ 74,261**	**$ 134**	**$ 174,089**	**$ 1,416,135**

Note: Values in thousands expressed in 2008 dollars.

FIGURE 3 – MPRP DEFERRED & OMITTED PROJECTS

DEFERRED PACKAGE PROJECT COST ESTIMATE & SCHEDULE SHEET

Transmission Owner: Central Maine Power
RSP Project #: Various
Project Name: Maine Power Reliability Program
Date: 6/29/2011
Estimate Grade: D (Construction)

1. Project Scope Summary

Central Maine Power is in the process of modernizing its 40 year-old bulk power transmission system by investing an estimated $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.

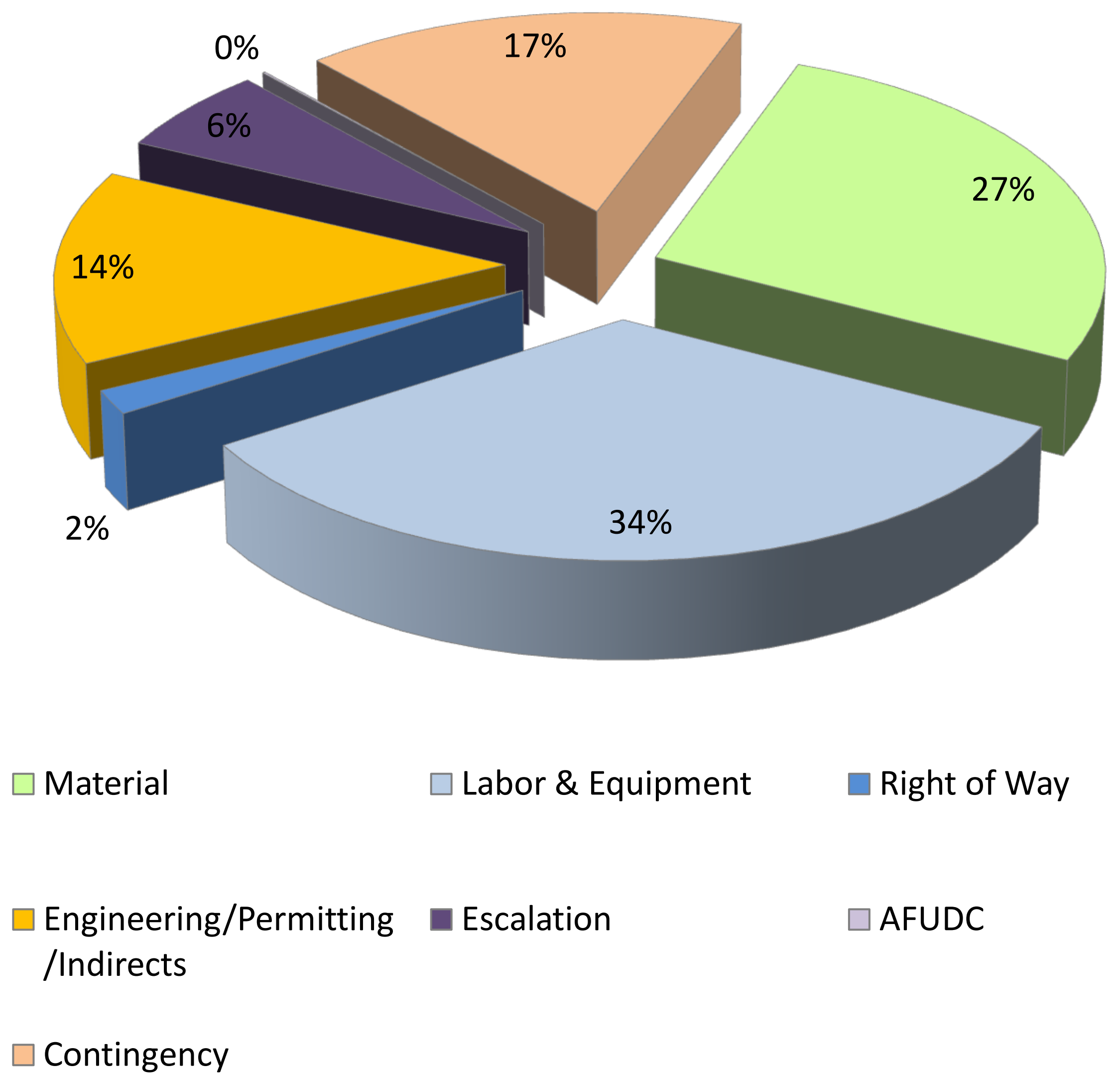
2. Project Cost Summary

Prior Estimated Cost:

2.1. Project Cost Summary

	PTF	Non-PTF*	Total
Material	$ 22,187	$ 1,776	$ 23,963
Labor & Equipment	$ 26,214	$ 3,314	$ 29,528
Right of Way	$ 1,397	$ 180	$ 1,577
Engineering/Permitting /Indirects	$ 11,386	$ 1,271	$ 12,657
Escalation	$ 5,132	$ 449	$ 5,581
AFUDC	$ 88	$ -	$ 88
Contingency	$ 14,051	$ 1,108	$ 15,159
Total Project Cost	**$ 80,456**	**$ 8,098**	**$ 88,554**

*Distribution costs in thousands carried in Non-PTF are estimated at $7,865



2.2 Detailed Cost Summary By Project Element

	Material	Labor & Equip.	Right of Way	Indirects	Escalation	AFUDC	Contingency	Total
2.2.1 New 345KV Lines	$ 8,492	$ 10,465	$ 559	$ 4,486	$ 1,978	$ -	$ 5,372	**$ 31,352**
2.2.2 New 115KV Lines	$ 3,065	$ 3,777	$ 202	$ 1,619	$ 714	$ -	$ 1,939	**$ 11,315**
2.2.3 New 345KV Substations	$ 4,182	$ 5,153	$ 275	$ 2,209	$ 974	$ -	$ 2,646	**$ 15,439**
2.2.4 New 115KV Substations	$ 718	$ 885	$ 47	$ 379	$ 167	$ -	$ 454	**$ 2,652**
2.2.5 345 KV Substations Expansions/Modifications	$ 1,382	$ 1,703	$ 91	$ 730	$ 322	$ 58	$ 874	**$ 5,161**
2.2.6 115 KV Substations Expansions/Modifications	$ 307	$ 379	$ 20	$ 162	$ 72	$ 30	$ 194	**$ 1,165**
2.2.7 Lines Rerates, Relocations, Rebuilds	$ 5,815	$ 7,166	$ 383	$ 3,072	$ 1,355	$ -	$ 3,679	**$ 21,469**
Total	**$ 23,963**	**$ 29,528**	**$ 1,577**	**$ 12,657**	**$ 5,581**	**$ 88**	**$ 15,159**	**$ 88,554**

Note: Values in thousands expressed in 2008 dollars.

ATTACHEMENT 3 – 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:	**$ 1,315,441**	**PPA Approval:**	
TCA Application #:	**CMP-08-TCA-01**	**Date:**	**6/29/2011**

1. Project Scope Summary

Central Maine Power is in the process of modernizing its 40 year-old bulk power transmission system by investing an estimated $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 Untilites 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 underway in all construction areas. Construction access roads and environmental controls are being installed by the T-line contractors and materials are being received. T-line Construction has begun in accordance with the Outage Sequence Plan, and to facilitate construction of substations within or near existing ROW. Site development is progressing at the new green field substations. Substation below grade construction is beginning at some of the larger facilities.

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	$ 466,115	$ 533,185	$ -	$ 114,349	$ 533,185	21%	$ -
2.2.2 New 115KV Lines	$ 168,221	$ 192,426	$ -	$ 20,937	$ 192,426	11%	$ -
2.2.3 New 345KV Substations	$ 229,537	$ 262,565	$ -	$ 47,940	$ 262,565	18%	$ -
2.2.4 New 115KV Substations	$ 39,426	$ 45,099	$ -	$ 6,635	$ 45,099	15%	$ -
2.2.5 345 KV Substations Expansions/Modifications	$ 76,014	$ 86,931	$ -	$ 24,322	$ 86,931	28%	$ -
2.2.6 115 KV Substations Expansions/Modifications	$ 16,950	$ 19,378	$ -	$ 4,441	$ 19,378	23%	$ -
2.2.7 Lines Rerates, Relocations, Rebuilds	$ 319,178	$ 365,104	$ -	$ 43,472	$ 365,104	12%	$ -
Grand Total	**$ 1,315,441**	**$ 1,504,689**	**$ -**	**$ 262,097**	**$ 1,504,689**	**18.30%**	**$ -**

Note: PTD Through the First Quarter of 2011

4. Project Forecast

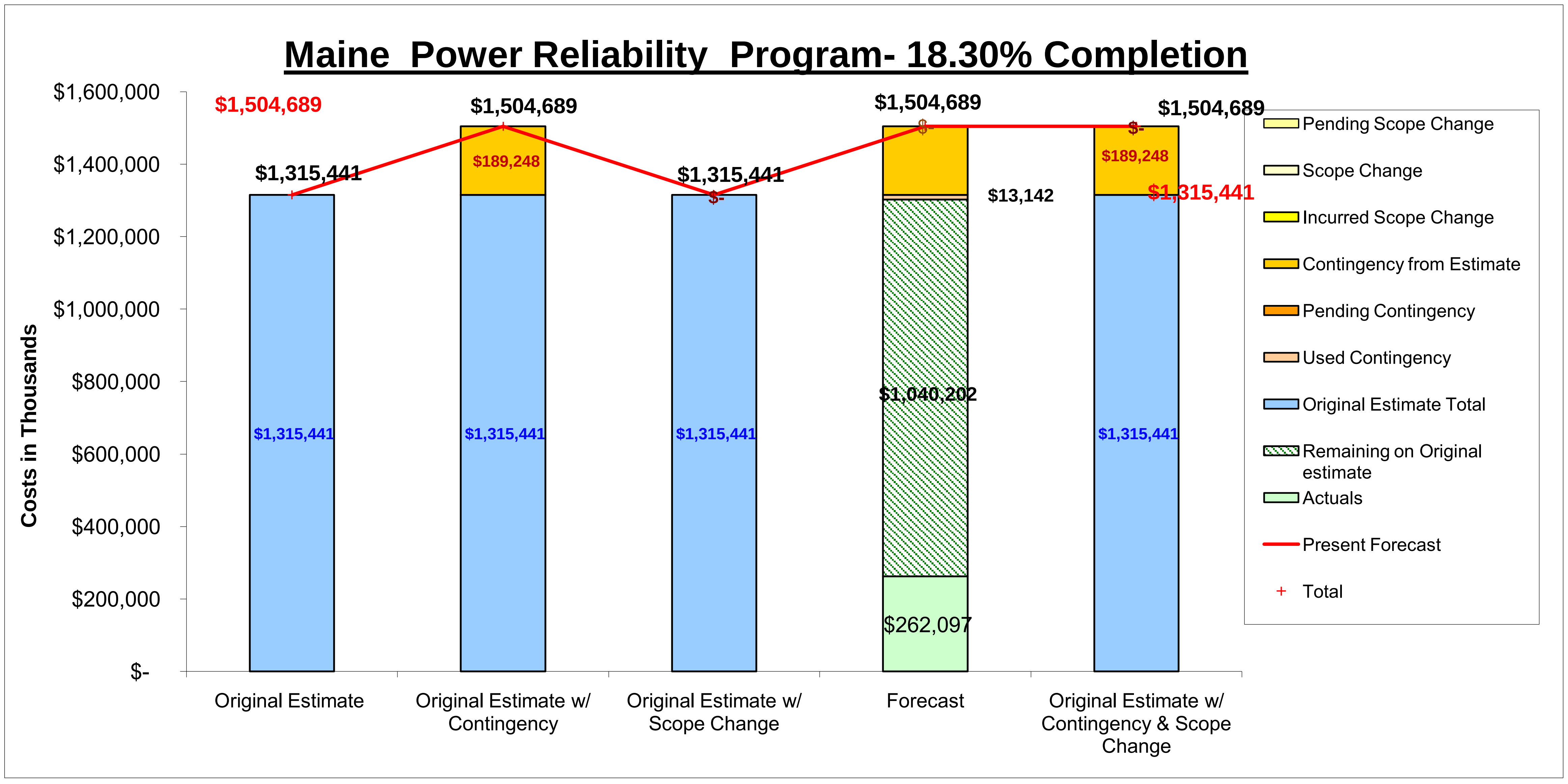


FIGURE 2 – MPRP SETTLEMENT PROJECTS

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:	**$ 1,257,045**	**PPA Approval:**	
TCA Application #:	**CMP-08-TCA-01**	**Date:**	**6/29/2011**

1. Project Scope Summary

Central Maine Power is in the process of modernizing its 40 year-old bulk power transmission system by investing an estimated $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.

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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	$ 445,451	$ 501,833	$ -	$ 112,710	$ 501,833	22%	$ -
2.2.2 New 115KV Lines	$ 160,763	$ 181,111	$ -	$ 20,637	$ 181,111	11%	$ -
2.2.3 New 345KV Substations	$ 219,361	$ 247,126	$ -	$ 47,253	$ 247,126	19%	$ -
2.2.4 New 115KV Substations	$ 37,678	$ 42,448	$ -	$ 6,540	$ 42,448	15%	$ -
2.2.5 345 KV Substations Expansions/Modifications	$ 72,593	$ 81,769	$ -	$ 23,974	$ 81,769	29%	$ -
2.2.6 115 KV Substations Expansions/Modifications	$ 16,172	$ 18,212	$ -	$ 4,377	$ 18,212	24%	$ -
2.2.7 Lines Rerates, Relocations, Rebuilds	$ 305,027	$ 343,636	$ -	$ 42,849	$ 343,636	12%	$ -
Grand Total	**$ 1,257,045**	**$ 1,416,135**	**$ -**	**$ 258,340**	**$ 1,416,135**	**18.24%**	**$ -**

Note: PTD Through the First Quarter of 2011

4. Project Forecast

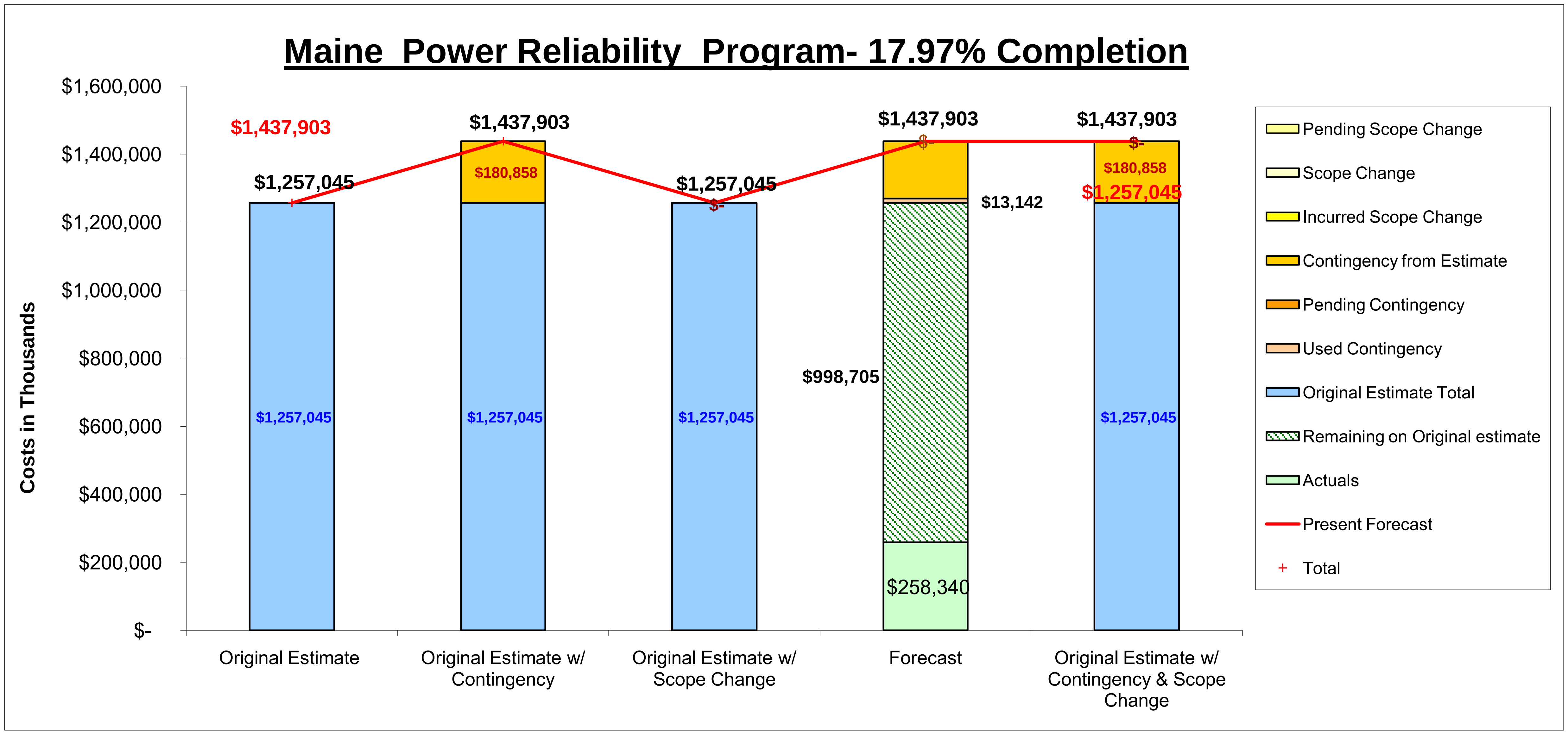


FIGURE 3 – MPRP DEFERRED & OMITTED PROJECTS

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:	**$ 73,395**	**PPA Approval:**	
TCA Application #:	**CMP-08-TCA-01**	**Date:**	**6/29/2011**

1. Project Scope Summary

Central Maine Power is in the process of modernizing its 40 year-old bulk power transmission system by investing an estimated $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 Untilites 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 underway in all construction areas. Construction access roads and environmental controls are being installed by the T-line contractors and materials are being received. T-line Construction has begun in accordance with the Outage Sequence Plan, and to facilitate construction of substations within or near existing ROW. Site development is progressing at the new green field substations. Substation below grade construction is beginning at some of the larger facilities.

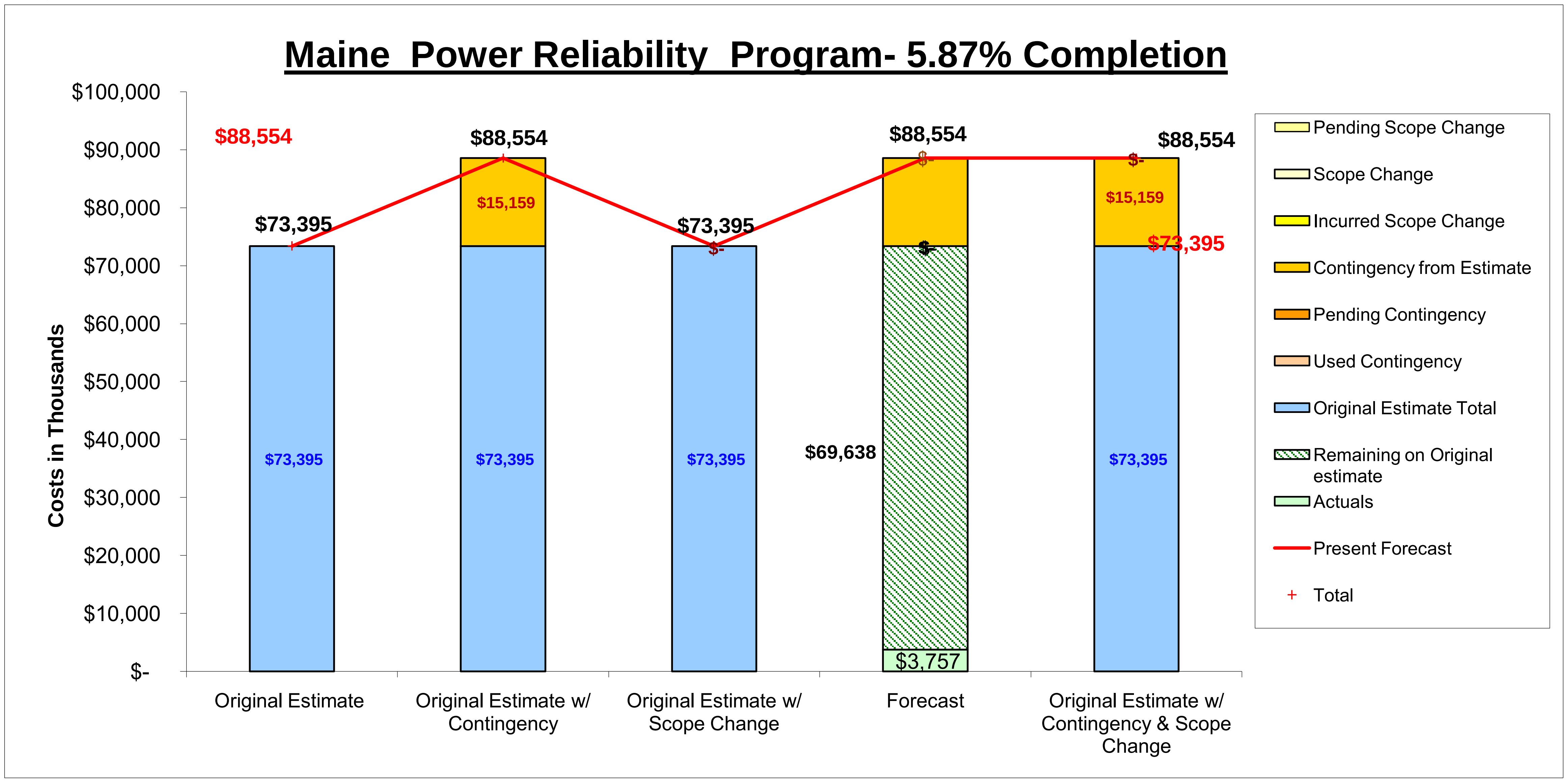
3. Project Cost Summary

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	$ 25,970	$ 31,342	$ -	$ 1,639	$ 31,342	5%	$ -
2.2.2 New 115KV Lines	$ 9,373	$ 11,311	$ -	$ 300	$ 11,311	3%	$ -
2.2.3 New 345KV Substations	$ 12,789	$ 15,435	$ -	$ 687	$ 15,435	4%	$ -
2.2.4 New 115KV Substations	$ 2,197	$ 2,651	$ -	$ 95	$ 2,651	4%	$ -
2.2.5 345 KV Substations Expansions/Modifications	$ 4,303	$ 5,178	$ -	$ 349	$ 5,178	7%	$ -
2.2.6 115 KV Substations Expansions/Modifications	$ 981	$ 1,175	$ -	$ 64	$ 1,175	5%	$ -
2.2.7 Lines Rerates, Relocations, Rebuilds	$ 17,783	$ 21,462	$ -	$ 623	$ 21,462	3%	$ -
Grand Total	**$ 73,395**	**$ 88,554**	**$ -**	**$ 3,757**	**$ 88,554**	**4.43%**	**$ -**

Note: PTD Through the First Quarter of 2011

4. Project Forecast



APPENDIX A – PROGRAM COST SUMMARY

MAINE POWER RELIABILITY PROGRAM (MPRP)
Program Cost Summary $/1000
as of 15-Jun-11

Settlement

Calendar Year	*Pre 2011 Total*	*2011*													*2012 Total*	*2013 Total*	*2014 Total*	*2015 Total*	*TOTAL*
		January	*February*	*March*	*April*	*May*	*June*	*July*	*August*	*September*	*October*	*November*	*December*	*2011 Total*					
Material	$ 19,739	$ 2,426	$ 3,011	$ 5,668	$ 5,219	$ 6,235	$ 6,032	$ 5,972	$ 6,202	$ 6,276	$ 5,718	$ 5,644	$ 5,297	$ 63,700	$ 85,375	$ 73,615	$ 38,644	$ -	$ 281,073
Labor	$ 56,646	$ 4,102	$ 5,138	$ 11,180	$ 16,251	$ 17,283	$ 16,857	$ 17,739	$ 18,991	$ 17,957	$ 17,264	$ 17,091	$ 17,307	$ 177,160	$ 168,209	$ 137,543	$ 82,914	$ -	$ 622,472
Right of Way	$ 33,137	$ 115	$ 109	$ 109	$ 91	$ 80	$ 88	$ 88	$ 79	$ 43	$ 20	$ 26	$ 15	$ 863	$ -	$ -	$ -	$ -	$ 34,000
Engineering / Permitting / Indirects	$ 96,729	$ 2,322	$ 2,887	$ 3,884	$ 3,539	$ 3,525	$ 3,751	$ 3,690	$ 3,660	$ 3,593	$ 3,499	$ 3,600	$ 3,509	$ 41,459	$ 31,381	$ 28,019	$ 27,491	$ 5,026	$ 230,105
Escalation	$ -	$ -	$ -	$ -	$ 382	$ 383	$ 425	$ 422	$ 434	$ 401	$ 382	$ 405	$ 384	$ 3,618	$ 20,297	$ 22,896	$ 21,334	$ 6,116	$ 74,261
AFUDC	$ 134	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 134
Contingency	$ 5,005	$ -	$ -	$ -	$ 2,503	$ 2,513	$ 2,929	$ 2,898	$ 2,016	$ 1,695	$ 1,548	$ 1,817	$ 1,624	$ 19,543	$ 12,334	$ 43,278	$ 89,559	$ 4,370	$ 174,089
Total	**$ 211,390**	**$ 8,965**	**$ 11,145**	**$ 20,840**	**$ 27,985**	**$ 30,019**	**$ 30,082**	**$ 30,809**	**$ 31,382**	**$ 29,965**	**$ 28,431**	**$ 28,583**	**$ 28,136**	**$ 306,342**	**$ 317,596**	**$ 305,351**	**$ 259,942**	**$ 15,513**	**$ 1,416,135**

Deferred

Calendar Year	*Pre 2011 Total*	*2011*													*2012 Total*	*2013 Total*	*2014 Total*	*2015 Total*	*TOTAL*
		January	*February*	*March*	*April*	*May*	*June*	*July*	*August*	*September*	*October*	*November*	*December*	*2011 Total*					
Material	$ 802	$ 4	$ 67	$ 16	$ 114	$ 125	$ 64	$ 54	$ 22	$ 20	$ 25	$ 30	$ 35	$ 576	$ 433	$ 4,332	$ 17,820	$ -	$ 23,963
Labor	$ 141	$ 7	$ 115	$ 12	$ 64	$ 70	$ 34	$ 29	$ 6	$ 8	$ 14	$ 16	$ 20	$ 395	$ 1,545	$ 11,425	$ 16,022	$ -	$ 29,528
Right of Way	$ 677	$ 1	$ 9	$ 1	$ 115	$ 117	$ 111	$ 108	$ 78	$ 66	$ 96	$ 103	$ 94	$ 900	$ -	$ -	$ -	$ -	$ 1,577
Engineering / Permitting / Indirects	$ 1,305	$ 16	$ 274	$ 35	$ 82	$ 87	$ 34	$ 61	$ 17	$ 33	$ 108	$ 23	$ 45	$ 815	$ 63	$ 312	$ 162	$ 10,000	$ 12,657
Escalation	$ -	$ -	$ -	$ -	$ 7	$ 8	$ 4	$ 3	$ 1	$ 1	$ 2	$ 2	$ 2	$ 30	$ 996	$ 670	$ 3,885	$ -	$ 5,582
AFUDC	$ 88	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 88
Contingency	$ -	$ -	$ -	$ -	$ 64	$ 71	$ 36	$ 30	$ 7	$ 8	$ 15	$ 17	$ 20	$ 268	$ 308	$ 13,804	$ 779	$ -	$ 15,159
Total	**$ 3,013**	**$ 28**	**$ 466**	**$ 63**	**$ 446**	**$ 478**	**$ 283**	**$ 285**	**$ 131**	**$ 136**	**$ 260**	**$ 191**	**$ 216**	**$ 2,985**	**$ 3,347**	**$ 30,543**	**$ 38,667**	**$ 10,000**	**$ 88,554**

Combined

Calendar Year	*Pre 2011 Total*	*2011*													*2012 Total*	*2013 Total*	*2014 Total*	*2015 Total*	*TOTAL*
		January	*February*	*March*	*April*	*May*	*June*	*July*	*August*	*September*	*October*	*November*	*December*	*2011 Total*					
Material	$ 20,541	$ 2,430	$ 3,078	$ 5,684	$ 5,333	$ 6,360	$ 6,096	$ 6,026	$ 6,224	$ 6,296	$ 5,743	$ 5,674	$ 5,332	$ 64,276	$ 85,808	$ 77,947	$ 56,463	$ -	$ 305,036
Labor	$ 56,687	$ 4,109	$ 5,253	$ 11,192	$ 16,315	$ 17,353	$ 16,891	$ 17,768	$ 18,997	$ 17,965	$ 17,278	$ 17,107	$ 17,327	$ 177,555	$ 169,854	$ 148,968	$ 98,936	$ -	$ 652,000
Right of Way	$ 33,914	$ 166	$ 167	$ 159	$ 156	$ 157	$ 149	$ 146	$ 117	$ 109	$ 116	$ 109	$ 109	$ 1,663	$ -	$ -	$ -	$ -	$ 35,577
Engineering / Permitting / Indirects	$ 98,053	$ 2,398	$ 3,072	$ 3,948	$ 3,621	$ 3,612	$ 3,785	$ 3,751	$ 3,677	$ 3,626	$ 3,607	$ 3,623	$ 3,554	$ 42,273	$ 31,444	$ 28,331	$ 27,635	$ 15,026	$ 242,763
Escalation	$ -	$ -	$ -	$ -	$ 389	$ 391	$ 429	$ 425	$ 435	$ 402	$ 384	$ 407	$ 386	$ 3,648	$ 21,293	$ 23,566	$ 25,219	$ 6,116	$ 79,843
AFUDC	$ 222	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 222
Contingency	$ 5,005	$ -	$ -	$ -	$ 2,567	$ 2,584	$ 2,965	$ 2,928	$ 2,023	$ 1,703	$ 1,563	$ 1,834	$ 1,644	$ 19,811	$ 12,642	$ 57,082	$ 90,338	$ 4,370	$ 189,248
Total	**$ 214,403**	**$ 8,993**	**$ 11,610**	**$ 20,904**	**$ 28,431**	**$ 30,497**	**$ 30,365**	**$ 31,094**	**$ 31,513**	**$ 30,101**	**$ 28,691**	**$ 28,774**	**$ 28,352**	**$ 309,327**	**$ 320,943**	**$ 335,894**	**$ 298,610**	**$ 25,513**	**$ 1,504,690**

APPENDIX B – MPRP COSTS THROUGH 2011 FOR CWIP FILING

MPRP Costs For 2011 for CWIP Filing

	PTF	Non-PTF	Distribution	Total
Projected Additional CWIP for 2011	$ 292,156,755	$ 1,437,375		$ 293,594,130
MPRP	$ 292,156,755	$ 1,437,375		$ 293,594,130
South Gorham				
Additional In Service 2011 from 2011 Spend	$ 3,322,870	$ -		$ 3,322,870
South Gorham	$ 3,322,870	$ -		$ 3,322,870
Retirements / Removals Costs in 2011	$ 3,200,000	$ 3,300,000		$ 6,500,000
Total (Less Lewiston)	**$ 298,679,625**	**$ 4,737,375**	**$ -**	**$ 303,417,000**
2011 Lewiston Preliminary Engineering (Not recoverable through rates)	$ 2,687,033			$ 2,687,033
2011 Distribution (Recovered through the ARP--Earning AFUDC)			$ 3,121,865	$ 3,121,865
Total MPRP Spend for 2011	**$ 301,366,658**	**$ 4,737,375**	**$ 3,121,865**	**$ 309,225,898**
CWIP Year End 2010	$ 182,322,304	$ 640,158		$ 182,962,462
In Service 2011	$ 47,087,340	$ 916,937		$ 48,004,277
MPRP	$ 43,764,470	$ 916,937		$ 44,681,407
South Gorham	$ 3,322,870			$ 3,322,870
In Service Year End 2010	$ 27,109,849	$ 709,204	$ -	$ 27,819,053
MPRP	$ -	$ -	$ -	$ -
South Gorham	$ 27,109,849	$ 709,204		$ 27,819,053
				$ -
Total In Service through 2011 (Less Lewiston)	**$ 74,197,189**	**$ 1,626,141**	**$ -**	**$ 75,823,330**
Total CWIP through 2011 (Less Lewiston)				**$ 431,875,185**

CMEEC
RR and Support Payment Summary
For Year 2010
Submitted May 2011

Support Payments / Revenue Requirements	Pre-97	Post-96
Support Payments to New England Power Company for Hydro-Quebec Phase II A.C. Transmission Facilities (Attachment F, Item K)	$58,134	
Support Payments to Boston Edison Company for Hydro-Quebec Phase II A.C. Transmission Facilities (Attachment F, Item K)	$3,869	
Support Payments to New England Hydro-Transmission Corporation for Hydro-Quebec Phase II Chester SVC Facility (Attachment F, Item K)	$24,191	
Revenue Requirements for Town of Wallingford, Electric Div. PTF Facilities	$80,610	$607,202
Revenue Requirements for Mohegan Tribal Utility Authority PTF Facilities	$0	$319,043
Revenue Requirements for City of Groton, Department of Utilities PTF Facilities	$0	$195,564
Revenue Requirements for Norwich, Department of Utilities PTF Facilities	$75,234	$28,160
Revenue Requirements for Bozrah Light and Power PTF Facilities	$0	$60,000
Total Support Payments and Revenue Requirements Less Revenues	**$242,038**	**$1,209,969**

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: 18-May-11

Revenue Requirements for (year): Year 2010

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:

	Pre-97 Revenue Requirements		Post-97 Revenue Requirements	
Total of Attachment F - Sections A through I =	0	(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)	0	(e)=(a)-(b)+(c)+(d)	0	(j)
Forecasted Transmisison Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	0		60,000	(k)
Annual True-up (per attachment C to Attachemnet F Implementation	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:	60,000	(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: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)	60,000	(l)=(k)+(b)+(g)-(h)

CMEEC
Bozrah Light and Power
For costs In 2011
FORECAST

			Attachment F		
🟨	Shading denotes an input		Regerence		
	I. FORECASTED TRANSMISSION REVENUE REQUIREMENTS	Period	Section:	POST-1996	Reference
Line No,					
1	Forecasted Transmission Plant Additions	2011	Appendix C	750,000	BL&P WO 26624 & associated notes
2	Carrying Charge Factor			8.00%	
3	Total Forecasted Revenue Requirements (Lines 1*2)			**60,000**	
	I. CARRYING CHARGE FACTOR				
4	Investment Return and Income Taxes			0	Worksheet 2, E56
5	Depreciation Expense			0	Worksheet 4, L12
6	Amortization of Loss on Reacquired Debt			0	Worksheet 4, L14
7	Investment Tax Credit			0	Worksheet 4, L16
8	Property Tax Expense			0	Worksheet 4, L21
9	Payroll Tax Expense			0	Worksheet 4, L42
10	Operation & Maintenance Expense			0	Worksheet 4, L29
11	Administrative & General Expense			0	Worksheet 4, L40
12	Total Expenses (Lines 4 thru 11)			0	
13	PTF Transmission Plant			0	Worksheet 1, L1
14	Carrying Charge Factor (Lines 12/13)			#DIV/0!	

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 18, 2011

Revenue Requirements for (year): Year 2010

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:

	Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I =	0	(a)	190,915	(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)	190,915	(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	0		4,649	(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:	195,564	(0) = (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)	195,564	(l)=(k)+(b)+(g)-(h)

City of Groton, Dept. of Utilities

PTF Revenue Requirements

Worksheet 1 of 7

🟨 Shading denotes an input

🟩 Modified since last filing

▨ Value changed by modification

Line No.	I. INVESTMENT BASE	Attachment F Reference *Section:*	GROTON	Reference
1	Transmission Plant	(A)(1)(a)	2,463,503	Worksheet 3, L10
2	General Plant	(A)(1)(b)	16,565	Worksheet 3, L11
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3, L14
4	Total Plant (Lines 1+2+3)		2,480,068	May 18, 2011
5	Accumulated Depreciation	(A)(1)(d)	2,096,317	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)		383,751	
10	Prepayments	(A)(1)(h)	0	Worksheet 3, L34
11	Materials & Supplies	(A)(1)(i)	79,240	Worksheet 3, L36
12	Cash Working Capital	(A)(1)(j)	3,792	Worksheet 3, 44
13	Total Investment Base (Line 9+10+11+12)		466,783	
II.	REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	37,343	Worksheet 2, E56
15	Depreciation Expense	(B)	68,487	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)	53,991	Worksheet 4, L21
19	Payroll Tax Expense	(F)	762	Worksheet 4, L42
20	Operation & Maintenance Expense	(G)	19,880	Worksheet 4, L29
21	Administrative & General Expense	(H)	10,452	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)		190,915	

🟨	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		25,238,664	DPUC Rpt. P. 201, line 10	100.00%	8.00%	8.00%	8.00%
TOTAL INVESTMENT RETURN	$	25,238,664		100.00%		8.00%	8.00%

Cost of Capital Rate=

(a) Weighted Cost of Capital	=		0.0800											
(b) Federal Income Tax	=	(	R.O.E. +	(	PTF Inv. (Tax Credit	+	Eq. AFUDC of Deprec. Exp.)	/	PTF Inv. Base)		x	Federal Income Tax Rate	)	
		(	1								-	Federal Income Tax Rate	)	
	=	(	0.0800	+(	0	+	0)	/	509	)	x	0.00%	)	
		(	1								-	0.00%	)	
	=		0.00%											
(c) State Income Tax	=	(	R.O.E. +	(	PTF Inv. (Tax Credit	+	Eq. AFUDC of Deprec. Exp.)	/	PTF Inv. Base)		+	Federal Income Tax	)*	State Income Tax Rate
		(	1								-	State Income Tax Rate	)	
	=	(	0.0800	+(	0	+	0)	/	509	)	+	0.00%	)*	0.00%
		(	1								-	0.00%	)	
	=		0.00%											
(a)+(b)+(c) **Cost of Capital Rate**	=		0.0800000											

		(PTF)	
INVESTMENT BASE	$	466,783	From Worksheet 1
x Cost of Capital Rate		8.00%	
= Investment Return and Income Taxes		37,343	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
	Transmission Plant						
1	Transmission Plant	7,964,062		7,964,062		$ 2,463,503	Used RSI numbers and G
2	General Plant	7,717,661	0.6939% (a)	53,553	30.9327%	16,565	DPUC Report-Page 502
3	Total (line 1+2)			8,017,615	May 18, 2011	2,480,068	
4	Transmission Plant Held for Future Use	0		0	30.9327%	0	None known
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	6,742,511		6,742,511	30.9327%	2,085,641	Used RSI Methodolgy
6	General Plant Accum.Depreciation	4,974,120	0.6939% (a)	34,515	30.9327%	10,676	Used RSI Methodolgy
7	Total (line 5+6)			6,777,026		2,096,317	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes	0	14.5232% (c)	0	30.9327%	0	None known
9	Accumulated Deferred Taxes	0	14.5232% (c)	0	30.9327%	0	None known
10	Total (line 8+9)			0		0	
11	Transmission loss on Reacquired Debt	0	14.5232% (c)	0	30.9327%	0	None known
	Other Regulatory Assets						
12	FAS 106	0	0.6939% (a)	0	30.9327%	0	None known
13	FAS 109	0	14.5232% (c)	0	30.9327%	0	None known
14	Other Regulatory Liabilities (254.DK)	0	14.5232% (c)	0	30.9327%	0	
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments	0	0.6939% (a)	0	30.9327%	0	Assumed none
17	Transmission Materials and Supplies	1,763,863	14.5232%	256,169	30.9327%	79,240	DPUC report-Page 200
18	Cash Working Capital						
19	Operation & Maintenance Expense					19,880	Worksheet 1, Line 20
20	Administrative & General Expense					10,452	Worksheet 1, Line 21
21	Transmission Support Expense					0	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					30,332	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					3,792	

(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

PTF Revenue Requirements
Worksheet 4 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
	Depreciation Expense						
1	Transmission Depreciation	219,930		219,930	30.9327%	68,030	
2	General Depreciation	213,126	0.6939% (a)	1,479	30.9327%	457	DPUC Report Page 508
3	Total (line 1+2)			221,409	May 18, 2011	68,487	
4	Amortization of Loss on Reacquired Debt	0	14.5232% (c)	0	30.9327%	0	None known
5	Amortization of Investment Tax Credits	0	14.5232% (c)	0	30.9327%	0	None known
	Property Taxes *						
6	Transmission Property Taxes	1,201,829	14.5232%	174,544	30.9327%	53,991	See below
7	General Property Taxes	0	0.6939% (a)	0	30.9327%	0	See below
8	Total (line 6+7)			174,544		53,991	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	64,270		64,270	30.9327%	19,880	DPUC Report-Page 518
10	Transmission of Electricity by Others - #565	0		0	30.9327%	0	
11	Load Dispatching - #561	0		0	30.9327%	0	
12	**Station Expenses & Rents - #562 / #567	0		0	30.9327%	0	DPUC Report-Page 518
13	O&M less lines 10, 11 & 12	64,270		64,270	30.9327%	19,880	
	Transmission Administrative and General						
14	Administrative and General	3,987,706					DPUC Report-Page 520
15	less Property Insurance (#924)	44,259					DPUC Report-Page 520
16	less Regulatory Commission Expenses (#928)	0					
17	less General Advertising Expense (#930.1)	0					assumed none
18	Subtotal [line 14 minus (15 thru 17)]	3,943,447	0.6939% (a)	27,364	30.9327%	8,464	
19	PLUS Property Insurance alloc. using Plant Allocatior	44,259	14.5232% (c)	6,428	30.9327%	1,988	
20	PLUS Regulatory Comm. Exp. (FERC Assessments)	0	14.5232% (c)	0	30.9327%	0	
21	PLUS Trans. Related General Advertising Expense	0	14.5232% (c)	0	30.9327%	0	
22	Total A&G [line 18 plus (19 thru 21)]	3,987,706		33,792		10,452	
23	Payroll Tax Expense	354,915	0.6939% (a)	2,463	30.9327%	762	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	354,915	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	354,915	To Line 23

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

City of Groton, Dept. of Utilities

PTF Revenue Requirements
Worksheet 5 of 7

▨ Shading denotes an input

Line No.			
	PTF Transmission Plant Allocation Factor	**GROTON**	Reference
1	PTF Transmission Investment	$ 2,463,503	Used RSI numbers
2	Total Transmission Investment	7,964,062	DPUC Report- May 18, 20
3	Percent Allocation (Line 1/Line 2)	30.9327%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	22,907	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)	22,907	
7	Total Wages and Salaries	4,759,095	DPUC Report-Page 507
8	Administrative and General Wages and Salaries	1,458,081	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)	3,301,014	
11	Percent Allocation (Line 6/Line 10)	0.6939%	
	Plant Allocation Factor		
12	Total Transmission Investment	7,964,062	Line 2
13	plus Transmission-Related General Plant (Line 2 of Wkst. 3)	53,553	Worksheet 3, Line 2
14	= Revised Numerator (Line 12 + Line 13)	8,017,615	
15	Total Plant in Service	55,205,653	DPUC Report-Page 502
16	Percent Allocation (Line 14 / Line 15)	14.5232%	

City of Groton, Dept. of Utilities

PTF Revenue Requirements
Worksheet 6 of 7

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)	TOTAL 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
For City of Groton Department of Utilities
For costs In 2011
FORECAST

			Attachment F Regerence Section:		
🟨	Shading denotes an input				
	I. FORECASTED TRANSMISSION REVENUE REQUIREMENTS	Period		POST-1996	Reference
Line No,					
1	Forecasted Transmission Plant Additions	2011	Appendix C	60,000	GU cost proj. ID 1235 GU -CL&P 1410 line NERC upgrades
2	Carrying Charge Factor			7.75%	
3	Total Forecasted Revenue Requirements (Lines 1*2)			**4,649**	

	I. CARRYING CHARGE FACTOR		
4	Investment Return and Income Taxes	37,343	Worksheet 2, E56
5	Depreciation Expense	68,487	Worksheet 4, L12
6	Amortization of Loss on Reacquired Debt	0	Worksheet 4, L14
7	Investment Tax Credit	0	Worksheet 4, L16
8	Property Tax Expense	53,991	Worksheet 4, L21
9	Payroll Tax Expense	762	Worksheet 4, L42
10	Operation & Maintenance Expense	19,880	Worksheet 4, L29
11	Administrative & General Expense	10,452	Worksheet 4, L40
12	Total Expenses (Lines 4 thru 11)	190,915	
13	PTF Transmission Plant	2,463,503	Worksheet 1, L1
14	Carrying Charge Factor (Lines 12/13)	7.75%	

Forecast Items Detail

Replace and/or extend poles to reduce line sag to meet NERC requirements,

CITY OF GROTON DEPARTMENT OF UTILITIES

	Completion			Buddington	TRANSMISSION			DISTRIBUTION			
Work order	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 Rellay 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						
				-	0						
				-	0						
				-	0						
				-	0						
				-	0						
				-	0						
				-	0						
				-	0						
				-	0						
				-	0						
				-	0						
				-	0						
				-	0						
Total				2,485,955		2,463,503	22,452	-	-	-	-
Allocated Common						-	-	-			
Transformers								-			
Total				2,485,955	2,485,955	2,463,503	22,452	-			

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 18, 2011

Revenue Requirements for (year): Year 2010

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:

	Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I =	75,234	(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)	75,234	(e)=(a)-(b)+(c)+(d)	0	(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	0		28,160	(k)
Annual True-up (per Attachment C to Attachment F Implementation I	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:	103,394	(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: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)	103,394	(l)=(k)+(b)+(g)-(h)

Norwich Public Utilities Year 2010 PTF Revenue Requirements

Worksheet 1 of 7

▨ Shading denotes an input

Line No.	I. INVESTMENT BASE	Attachment F Reference *Section:*	NPU	Reference
1	Transmission Plant	(A)(1)(a)	$375,392	Worksheet 3, Line 1
2	General Plant	(A)(1)(b)	$24,602	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)		$399,994	
5	Accumulated Depreciation	(A)(1)(d)	$318,187	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)		$81,807	
10	Prepayments	(A)(1)(h)	$490	Worksheet 3, Line 16
11	Materials & Supplies	(A)(1)(i)	$3,519	Worksheet 3, Line 17
12	Cash Working Capital	(A)(1)(j)	$4,835	Worksheet 3, Line 24
13	Total Investment Base (Line 9 + 10 + 11 + 12)		$90,651	
II.	REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	$7,252	Worksheet 2
15	Depreciation Expense	(B)	$17,720	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)	$10,949	Worksheet 4, Line 8
19	Payroll Tax Expense	(F)	$630	Worksheet 4, Line 23
20	Operation & Maintenance Expense	(G)	$16,917	Worksheet 4, Line 13
21	Administrative & General Expense	(H)	$21,766	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)		$75,234	

Norwich Public Utilities
Annual Revenue Requirements
for costs in 2010

▨ 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	0.00%	4.00%	0.00%	0.00%
PREFERRED STOCK		of Muni RNS audit total investment return should = 8%)	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	32,086,351	DPUC Rpt. P. 201, line 10	100.00%	8.00%	8.00%	8.00%
TOTAL INVESTMENT RETURN	$ 32,086,351		100.00%		8.00%	8.00%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0800

(b) Federal Income Tax

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

$$= \frac{\left(0.0800 + \left(0 + 0\right) / 90{,}651\right) \times 0.00\%\right)}{\left(1 - 0.00\%\right)}$$

= 0.00%

(c) State Income Tax

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

$$= \frac{\left(0.0800 + \left(0 + 0\right) / 90{,}651\right) + 0.00\%\right) * 0.00\%}{\left(1 - 0.00\%\right)}$$

= 0.00%

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

	(PTF)	
INVESTMENT BASE	$ 90,651	From Worksheet 1
x Cost of Capital Rate	8.00%	
= Investment Return and Income Taxes	7,252	To Worksheet 1

Norwich Public Utilities **Year 2010**

PTF Revenue Requirements
Worksheet 3 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	Reference
	Transmission Plant						
1	Transmission Plant	$ 5,137,320		5,137,320		375,392	DPUC Annual Rpt. p. 500
2	General Plant	$ 14,063,387	2.3940% (a)	336,677	7.3072%	24,602	DPUC Annual Rpt. p. 501
3	Total (line 1 + 2)			5,473,997		399,994	
4	Transmission Plant Held for Future Use	0		0	7.3072%	0	information not available
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	4,161,395		4,161,395	7.3072%	304,081	DPUC Annual Rpt. p. 508, line 3
6	General Plant Accum.Depreciation	8,063,523	2.3940% (a)	193,041	7.3072%	14,106	DPUC Annual Rpt. p. 508, line 3
7	Total (line 5 + 6)			4,354,436		318,187	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes	0	9.7158% (c)	0	7.3072%	0	Not applicable.
9	Accumulated Deferred Taxes	0	9.7158% (c)	0	7.3072%	0	Not applicable.
10	Total (line 8 + 9)			0		0	
11	Transmission loss on Reacquired Debt	0	9.7158% (c)	0	7.3072%	0	Not applicable.
	Other Regulatory Assets						
12	FAS 106	0	2.3940% (a)	0	7.3072%	0	Not applicable.
13	FAS 109	0	9.7158% (c)	0	7.3072%	0	Not applicable.
14	Other Regulatory Liabilities (254.DK)	0	9.7158% (c)	0	7.3072%	0	Not applicable.
15	Total (line 12 + 13 + 14)	0		0		0	
16	Transmission Prepayments	280,077	2.3940% (a)	6,705	7.3072%	490	DPUC Annual Rpt, p. 210, line 1
17	Transmission Materials and Supplies	495,665	9.7158%	48,158	7.3072%	3,519	DPUC Report page 200 Line 25
18	Cash Working Capital						
19	Operation & Maintenance Expense					16,917	Worksheet 4, Line 13
20	Administrative & General Expense					21,766	Worksheet 4, Line 22
21	Transmission Support Expense					0	Worksheet 1, Line 24
22	Subtotal (line 19 + 20 + 21)					38,683	
23						0.125	x 45 days / 360
24	Total (line 22 * line 23)					4,835	

Norwich Public Utilities Year 2010

PTF Revenue Requirements
Worksheet 4 of 7

▨ Shading denotes an input

Line No.		(1) (1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Reference
	Depreciation Expense						
1	Transmission Depreciation	227,583		227,583	7.3072%	16,630	
2	General Depreciation	623,006	2.3940% (a)	14,915	7.3072%	1,090	DPUC Annual Rpt. p. 508, line 3
3	Total (line 1+2)			242,498		17,720	
4	Amortization of Loss on Reacquired Debt	0	9.7158% (c)	0	7.3072%	0	not applicable
5	Amortization of Investment Tax Credits	0	9.7158% (c)	0	7.3072%	0	not applicable
	Property Taxes *						
6	Transmission Property Taxes	1,542,202	9.7158%	149,837	7.3072%	10,949	See Below
7	General Property Taxes	0	2.3940% (a)	0	7.3072%	0	information not available
8	Total (line 6+7)			149,837		10,949	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	282,650		282,650	7.3072%	20,654	DPUC Annual Rpt. P. 518,
10	Transmission of Electricity by Others - #565	0		0	7.3072%	0	Information not available.
11	Load Dispatching - #561	0		0	7.3072%	0	DPUC Annual Rpt. P. 518, line 31
12	**Station Expenses & Rents - #562 / #567	51,140		51,140	7.3072%	3,737	DPUC Annual Rpt. P. 518, line 32 & 37
13	O&M less lines 10, 11 & 12	231,510		282,650	7.3072%	16,917	
	Transmission Administrative and General						
14	Administrative and General	12,006,632					DPUC Annual Rpt. P. 520, line 18
15	less Property Insurance (#924)	142,535					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)]	11,864,097	2.3940% (a)	284,026	7.3072%	20,754	
19	PLUS Property Insurance alloc. using Plant Allocator	142,535	9.7158% (c)	13,848	7.3072%	1,012	
20	PLUS Regulatory Comm. Exp. (FERC Assessments)	0	9.7158% (c)	0	7.3072%	0	Not applicable.
21	PLUS Trans. Related General Advertising Expense	0	9.7158% (c)	0	7.3072%	0	Not applicable.
22	Total A&G [line 18 plus (19 thru 21)]	12,006,632		297,874		21,766	
	Payroll Tax Expense						
	Federal Unemployment	0	2.3940% (a)	0	7.3072%	0	information not available
	FICA	360,064	2.3940% (a)	8,620	7.3072%	630	information not available
	Medicare	0	2.3940% (a)	0	7.3072%	0	information not available
	CT Unemployment	0	2.3940% (a)	0	7.3072%	0	information not available
23		360,064	2.3940% (a)	8,620	7.3072%	630	

(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 12/31/2010	56,341,033	DPUC Annual Rpt. P. 501, line 18
Less Furniture & Fixtures	1,301,707	DPUC Annual Rpt. P. 501, line 4
Net Taxable Plant	55,039,326	
Applicable Mill Rate	28.02	From Town
	1,542,202	Place in cell d6 above.

Norwich Public Utilities Year 2010

PTF Revenue Requirements
Worksheet 5 of 7

🟨 Shading denotes an input

Line No.		NPU	Reference
	PTF Transmission Plant Allocation Factor		
1	PTF Transmission Investment	$375,392	Auditor's tab
2	Total Transmission Investment	$5,137,320	DPUC Annual Rpt. P. 500
3	Percent Allocation (Line 1/Line 2)	7.3072%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	$205,842	DPUC Annual Rpt. P. 507, line 4
5	Affiliated Company Transmission Wages and Salaries	$0	Worksheet 6
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	$205,842	
7	Total Wages and Salaries	$11,266,481	DPUC Annual Rpt. P. 507, line 45
8	Administrative and General Wages and Salaries	$2,668,220	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)	$8,598,261	
11	Percent Allocation (Line 6/Line 10)	2.3940%	
	Plant Allocation Factor		
12	Total Transmission Investment	$5,137,320	DPUC Annual Rpt. P. 500
13	plus Transmission-Related General Plant	$336,677	Worksheet 3, Line 2
14	= Revised Numerator (Line 12 + Line 13)	$5,473,997	
15	Total Plant in Service	$56,341,033	DPUC Annual Rpt. P. 501
16	Percent Allocation (Line 14 / Line 15)	9.7158%	

Norwich Public Utilities

PTF Revenue Requirements
Worksheet 6 of 7

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		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)	TOTAL 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)

CMEEC
For Norwich Public Utilities
For costs In 2011
FORECAST

🟨 Shading denotes an input

Line No,	I. FORECASTED TRANSMISSION REVENUE REQUIREMENTS	Period	Attachment F Regerence Section:	POST-1996	Reference
1	Forecasted Transmission Plant Additions	2011	Appendix C	140,509	
2	Carrying Charge Factor			20.04%	
3	Total Forecasted Revenue Requirements (Lines 1*2)			**28,160**	
	I. CARRYING CHARGE FACTOR				
4	Investment Return and Income Taxes			7,252	Worksheet 2, E56
5	Depreciation Expense			17,720	Worksheet 4, L12
6	Amortization of Loss on Reacquired Debt			0	Worksheet 4, L14
7	Investment Tax Credit			0	Worksheet 4, L16
8	Property Tax Expense			10,949	Worksheet 4, L21
9	Payroll Tax Expense			630	Worksheet 4, L42
10	Operation & Maintenance Expense			16,917	Worksheet 4, L29
11	Administrative & General Expense			21,766	Worksheet 4, L40
12	Total Expenses (Lines 4 thru 11)			75,234	
13	PTF Transmission Plant			375,392	Worksheet 1, L1
14	Carrying Charge Factor (Lines 12/13)			20.04%	

Forecasted Items Detail	**Cost**
Primary Relay (SEL-311L)	$8,770
Backup Relay (GE D60)	$10,305
Engineering & Design	$56,734
Fiber	$27,500
Communications Interface	$5,500
Installation & Test	$10,200
Panel Fabrication	$7,600
NPU Labor	$10,400
Other Material	$3,500
TOTAL:	**$140,509**

	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	2,875	0				2,875		
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	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
	-	0						
Total	1,851,217		356,661	91,499	1,099,523	81,278	-	222,255
Allocated Common			18,730	4,805	57,743			
Transformers					222,255			
Total	1,851,217	471,696	375,392	96,305	1,379,520			

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 18, 2011
Revenue Requirements for (year):	Year 2010
Customer:	Town of Wallingford, Electric Division
Customer's NABs Number:	8
Name of Participant responsible for customer's billing:	CMEEC
DUNs number of Participant responsible for customer's billing:	

		Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	=	80,982	(a)	607,202	(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)		(372)	(d)	0	(i)
Sub Total - Sum (A through I) - J + K + (L through O)		80,610	(e)=(a)-(b)+(c)+(d)	607,202	(j)

Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:	687,812	(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: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)	687,812	(l)=(k)+(b)+(g)-(h)

Town of Wallingford, Electric Division Year 2010

PTF Revenue Requirements
Worksheet 1 of 7

▨ Shading denotes an input

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	WALLINGFORD	Reference
1	Transmission Plant	(A)(1)(a)	$6,282,177	Worksheet 3, Line 1
2	General Plant	(A)(1)(b)	$80,588	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)		$6,362,765	
5	Accumulated Depreciation	(A)(1)(d)	$2,654,372	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)		$3,708,393	
10	Prepayments	(A)(1)(h)	$0	Worksheet 3, Line 16
11	Materials & Supplies	(A)(1)(i)	$50,444	Worksheet 3, Line 17
12	Cash Working Capital	(A)(1)(j)	$7,624	Worksheet 3, Line 24
13	Total Investment Base (Line 9 + 10 + 11 + 12)		$3,766,461	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	$301,317	Worksheet 2
15	Depreciation Expense	(B)	$177,304	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)	$148,568	Worksheet 4, Line 8
19	Payroll Tax Expense	(F)	$0	Worksheet 4, Line 23
20	Operation & Maintenance Expense	(G)	$32,290	Worksheet 4, Line 13
21	Administrative & General Expense	(H)	$28,705	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)	($372)	
28	Transmission Rents Received from Electric Property	(O)	$0	
29	Total Revenue Requirements (Line 14 thru 28)		$687,812	

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

▨ 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	0.00%	6.00%	0.00%	0.00%
PREFERRED STOCK		0	of Muni RNS audit total investment return should = 8%)	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY		58,355,659	DPUC Rpt. P. 201, line 10	100.00%	8.00%	8.00%	8.00%
TOTAL INVESTMENT RETURN	$	58,355,659		100.00%		8.00%	8.00%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0800

(b) Federal Income Tax

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

$$= \frac{(0.0800 + (0 + 0) / 3{,}766{,}461) \text{ x } 0.00\%)}{(1 - 0.00\%)}$$

= 0.00%

(c) State Income Tax

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

$$= \frac{(0.0800 + (0 + 0) / 3{,}766{,}461) + 0.00\%)^{*} \; 0.00\%}{(1 - 0.00\%)}$$

= 0.00%

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

		(PTF)	
INVESTMENT BASE	$	3,766,461	From Worksheet 1
x Cost of Capital Rate		8.00%	
= Investment Return and Income Taxes		301,317	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
	Transmission Plant						
1	Transmission Plant	$ 9,039,975		9,039,975		6,282,177	DPUC Annual Rpt. p. 501, line 2
2	General Plant	$ 9,357,314	1.2393% (a)	115,965	69.4933%	80,588	DPUC Annual Rpt. p. 502, line 1
3	Total (line 1 + 2)			9,155,940		6,362,765	
4	Transmission Plant Held for Future Use	0		0	69.4933%	0	
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	3,556,251		3,556,251	69.4933%	2,598,060	DPUC Annual Rpt. p. 508, line 3
6	General Plant Accum.Depreciation	6,538,498	1.2393% (a)	81,032	69.4933%	56,312	DPUC Annual Rpt. p. 508, line 3
7	Total (line 5 + 6)			3,637,283		2,654,372	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes	0	9.4079% (c)	0	69.4933%	0	not applicable
9	Accumulated Deferred Taxes	0	9.4079% (c)	0	69.4933%	0	not applicable
10	Total (line 8 + 9)			0		0	
11	Transmission loss on Reacquired Debt	0	9.4079% (c)	0	69.4933%	0	not applicable
	Other Regulatory Assets						
12	FAS 106	0	1.2393% (a)	0	69.4933%	0	not applicable
13	FAS 109	0	9.4079% (c)	0	69.4933%	0	not applicable
14	Other Regulatory Liabilities (254.DK)	0	9.4079% (c)	0	69.4933%	0	not applicable
15	Total (line 12 + 13 + 14)	0		0		0	
16	Transmission Prepayments	0	1.2393% (a)	0	69.4933%	0	Assumed none
17	Transmission Materials and Supplies	771,579	9.4079%	72,589	69.4933%	50,444	DPUC Report page 200 Line 25
18	Cash Working Capital						
19	Operation & Maintenance Expense					32,290	Worksheet 4, Line 13
20	Administrative & General Expense					28,705	Worksheet 4, Line 22
21	Transmission Support Expense					0	Worksheet 1, Line 24
22	Subtotal (line 19 + 20 + 21)					60,995	
23						0.125	x 45 days / 360
24	Total (line 22 * line 23)					7,624	

Town of Wallingford, Electric Division

🟨 Shading denotes an input

Line No.		(1) (1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Reference
	Depreciation Expense						
1	Transmission Depreciation	251,287		251,287	69.4933%	174,628	25 Year Depreciation
2	General Depreciation	310,766	1.2393% (a)	3,851	69.4933%	2,676	DPUC Annual Rpt. p. 508, line 3
3	Total (line 1+2)			255,138		177,304	
4	Amortization of Loss on Reacquired Debt	0	9.4079% (c)	0	69.4933%	0	not applicable
5	Amortization of Investment Tax Credits	0	9.4079% (c)	0	69.4933%	0	not applicable
	Property Taxes *						
6	Transmission Property Taxes	2,272,424	9.4079%	213,787	69.4933%	148,568	See Below
7	General Property Taxes	0	1.2393% (a)	0	69.4933%	0	information not available
8	Total (line 6+7)			213,787		148,568	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	46,465		46,465	69.4933%	32,290	DPUC Annual Rpt. p. 518, line 47
10	Transmission of Electricity by Others - #565	0		0	69.4933%	0	information not available
11	Load Dispatching - #561	0		0	69.4933%	0	information not available
12	**Station Expenses & Rents - #562 / #567	0		0	69.4933%	0	information not available
13	O&M less lines 10, 11 & 12	46,465		46,465	69.4933%	32,290	
	Transmission Administrative and General						
14	Administrative and General	3,073,354					DPUC Annual Rpt. p. 520, line 18
15	less Property Insurance (#924)	39,403					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)]	3,033,951	1.2393% (a)	37,600	69.4933%	26,129	
19	PLUS Property Insurance alloc. using Plant Allocator	39,403	9.4079% (c)	3,707	69.4933%	2,576	
20	PLUS Regulatory Comm. Exp. (FERC Assessments)	0	9.4079% (c)	0	69.4933%	0	not applicable
21	PLUS Trans. Related General Advertising Expense	0	9.4079% (c)	0	69.4933%	0	not applicable
22	Total A&G [line 18 plus (19 thru 21)]	3,073,354		41,307		28,705	
	Payroll Tax Expense						
	Federal Unemployment	0	1.2393% (a)	0	69.4933%	0	information not available
	FICA	0	1.2393% (a)	0	69.4933%	0	information not available
	Medicare	0	1.2393% (a)	0	69.4933%	0	information not available
	CT Unemployment	0	1.2393% (a)	0	69.4933%	0	information not available
23		0	1.2393% (a)	0	69.4933%	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 12/31/2010	97,321,663	DPUC Report Page 502 Line18
Less Furniture & Fixtures	2,951,914	DPUC Report Page 502 Line4
Net Taxable Plant	94,369,749	
Applicable Mil Rate	24.08	
	2,272,424	To cell d6 above

Town of Wallingford, Electric Division

🟨 Shading denotes an input

Line No.			
	PTF Transmission Plant Allocation Factor	**WALLINGFORD**	Reference
1	PTF Transmission Investment	$6,282,177	Auditor's tab
2	Total Transmission Investment	$9,039,975	DPUC Page 501 line22
3	Percent Allocation (Line 1/Line 2)	69.4933%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	$46,014	DPUC Annual Rpt. P. 507, line 4
5	Affiliated Company Transmission Wages and Salaries	$0	Worksheet 6
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	$46,014	
7	Total Wages and Salaries	$4,331,252	DPUC Annual Rpt. P. 507, line 44
8	Administrative and General Wages and Salaries	$618,304	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)	$3,712,948	
11	Percent Allocation (Line 6/Line 10)	1.2393%	
	Plant Allocation Factor		
12	Total Transmission Investment	$9,039,975	DPUC Page 501 line22
13	plus Transmission-Related General Plant	$115,965	Worksheet 3, Line 2
14	= Revised Numerator (Line 12 + Line 13)	$9,155,940	
15	Total Plant in Service	$97,321,663	DPUC Annual Rpt. P. 502, line 18
16	Percent Allocation (Line 14 / Line 15)	9.4079%	

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		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

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.

			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]		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			
	TOTAL	TOTAL	PTF	NON PTF	NON PTF	COMMON	PTF XFR	NPTF XFR
	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			531,923	326,667	1,358,678			
Transformers					27,488			
Total	3,044,353	1,168,217	723,746	444,471	1,876,136			

	N. WALLINGFORD	TRANSMISSION						
	TOTAL	TOTAL	PTF	NON PTF	DISTRIBUTION	COMMON	PTF XFR	NPTF XFR
	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			85,896	43,906	705,852			
Transformers					406,833			
Total	2,028,054	251,824	166,644	85,180	1,776,230			
Total Redistribution	5,072,407	1,420,041	890,390	529,651	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%	28.49%	57.49%			
			2,700,681					

Nusco-Wallingford 13M substation rebuild project

Newly Installed 2007				
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: May 18, 2011

Revenue Requirements for (year): Year 2010

Customer: Mohegan Tribal Utility Authority

Customer's NABs Number: 8

Name of Participant responsible for customer's billing: CMEEC

DUNs number of Participant responsible for customer's billing:

		Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	=	0	(a)	$ 319,043	(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)	$ 319,043	(j)

Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:	$ 319,043	(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: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)	$ 319,043	(l)=(k)+(b)+(g)-(h)

▨ Shading denotes an input

Line No.	I. INVESTMENT BASE		Attachment F Reference Section:	MTUA	Reference
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)	$969,967	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	0	(A)(1)(g)	$0	Worksheet 3, Line 15
9	Net Investment (Line 4 - 5 - 6 + 7 + 8)			$1,724,385	
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)	$1,605	Worksheet 3, Line 24
13	Total Investment Base (Line 9 + 10 + 11 + 12)			$1,725,990	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	$138,079	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)	$60,353	Worksheet 4, Line 8
19	Payroll Tax Expense	(F)	$0	Worksheet 4, Line 23
20	Operation & Maintenance Expense	(G)	$12,837	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)		$319,043	

Mohegan Tribal Utility Authority

Annual Revenue Requirements
for costs in 2010

🟨 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	0.00%	6.00%	0.00%	0.00%
PREFERRED STOCK		0	of Muni RNS audit total investment return should = 8%)	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY		6,000,000	Historical	100.00%	8.00%	8.00%	8.00%
TOTAL INVESTMENT RETURN	0	6,000,000		100.00%		8.00%	8.00%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0800

(b) Federal Income Tax

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

$$= \frac{(\ 0.0800\ +(\ 0\ +\ 0\ )\ /\ 1{,}725{,}990\ )\ \text{x}\ 0.00\%\ )}{(\ 1\ -\ 0.00\%\ )}$$

= 0.00%

(c) State Income Tax

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

$$= \frac{(\ 0.0800\ +(\ 0\ +\ 0\ )\ /\ 1{,}725{,}990\ )\ +\ 0.00\%\ )^{*}\ 0.00\%}{(\ 1\ -\ 0.00\%\ )}$$

= 0.00%

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

		(PTF)	
INVESTMENT BASE	$	1,725,990	From Worksheet 1
x Cost of Capital Rate		8.00%	
= Investment Return and Income Taxes		138,079	To Worksheet 1

Mohegan Tribal Utility Authority

🟨 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
	Transmission Plant						
1	Transmission Plant	$ 6,059,395		6,059,395	44.4657%	2,694,352	See Inventory Tab
2	General Plant		100.0000% (a)	0	44.4657%	0	
3	Total (line 1 + 2)			6,059,395		2,694,352	
4	Transmission Plant Held for Future Use	0		0	44.4657%	0	
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	2,181,382		2,181,382	44.4657%	969,967	
6	General Plant Accum.Depreciation	0	100.0000% (a)	0	44.4657%	0	
7	Total (line 5 + 6)			2,181,382		969,967	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes	0	100.0000% (c)	0	44.4657%	0	not applicable
9	Accumulated Deferred Taxes	0	100.0000% (c)	0	44.4657%	0	not applicable
10	Total (line 8 + 9)			0		0	
11	Transmission loss on Reacquired Debt	0	100.0000% (c)	0	44.4657%	0	not applicable
	Other Regulatory Assets						
12	FAS 106	0	100.0000% (a)	0	44.4657%	0	not applicable
13	FAS 109	0	100.0000% (c)	0	44.4657%	0	not applicable
14	Other Regulatory Liabilities (254.DK)	0	100.0000% (c)	0	44.4657%	0	not applicable
15	Total (line 12 + 13 + 14)	0		0		0	
16	Transmission Prepayments	0	100.0000% (a)	0	44.4657%	0	information not available
17	Transmission Materials and Supplies	0	100.0000%	0	44.4657%	0	information not available
18	Cash Working Capital						
19	Operation & Maintenance Expense					12,837	Worksheet 4, Line 13
20	Administrative & General Expense					0	Worksheet 4, Line 22
21	Transmission Support Expense					0	Worksheet 1, Line 24
22	Subtotal (line 19 + 20 + 21)					12,837	
23						0.125	x 45 days / 360
24	Total (line 22 * line 23)					1,605	

Mohegan Tribal Utility Authority

▨ Shading denotes an input

Line No.		(1) (1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Reference
	Depreciation Expense						
1	Transmission Depreciation	242,376		242,376	44.4657%	107,774	25 year depreciation
2	General Depreciation	0	100.0000% (a)	0	44.4657%	0	
3	Total (line 1+2)			242,376		107,774	
4	Amortization of Loss on Reacquired Debt	0	100.0000% (c)	0	44.4657%	0	not applicable
5	Amortization of Investment Tax Credits	0	100.0000% (c)	0	44.4657%	0	not applicable
		9,695					
	Property Taxes *						
6	Transmission Property Taxes	135,730	100.0000%	135,730	44.4657%	60,353	See Below
7	General Property Taxes	0	100.0000% (a)	0	44.4657%	0	information not available
8	Total (line 6+7)			135,730		60,353	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	28,870		28,870	44.4657%	12,837	MTUA
10	Transmission of Electricity by Others - #565	0		0	44.4657%	0	information not available
11	Load Dispatching - #561	0		0	44.4657%	0	information not available
12	**Station Expenses & Rents - #562 / #567	0		0	44.4657%	0	information not available
13	O&M less lines 10, 11 & 12	28,870		28,870	44.4657%	12,837	
	Transmission Administrative and General						
14	Administrative and General	0					information not available
15	less Property Insurance (#924)	0					information not available
16	less Regulatory Commission Expenses (#928)	0					information not available
17	less General Advertising Expense (#930.1)	0					information not available
18	Subtotal [line 14 minus (15 thru 17)]	0	100.0000% (a)	0	44.4657%	0	
19	PLUS Property Insurance alloc. using Plant Allocator	0	100.0000% (c)	0	44.4657%	0	
20	PLUS Regulatory Comm. Exp. (FERC Assessments)	0	100.0000% (c)	0	44.4657%	0	not applicable
21	PLUS Trans. Related General Advertising Expense	0	100.0000% (c)	0	44.4657%	0	not applicable
22	Total A&G [line 18 plus (19 thru 21)]	0		0		0	
	Payroll Tax Expense						
	Federal Unemployment	0	100.0000% (a)	0	44.4657%	0	information not available
	FICA	0	100.0000% (a)	0	44.4657%	0	information not available
	Medicare	0	100.0000% (a)	0	44.4657%	0	information not available
	CT Unemployment	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 12/31/2010	6,059,395	
Less Furniture & Fixtures	0	
Net Taxable Plant	6,059,395	
Applicable Mil Rate	22.40	
	135,730	To cell d6 above

Mohegan Tribal Utility Authority

🟨 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 Fac 0		
4	Direct Transmission Wages and Salaries	$12,220	MTUA
5	Affiliated Company Transmission Wages and Salaries	$0	Worksheet 6
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	$12,220	
7	Total Wages and Salaries	$12,220	
8	Administrative and General Wages and Salaries	$0	Information not availiable
9	Affiliated Company Wages and Salaries less A&G	$0	Information not availiable
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	$12,220	
11	Percent Allocation (Line 6/Line 10)	100.0000%	
	Plant Allocation Factor		
12	Total Transmission Investment	$6,059,395	See Inventory Tab
13	plus Transmission-Related General Plant	$0	Worksheet 3, Line 2
14	= Revised Numerator (Line 12 + Line 13)	$6,059,395	
15	Total Plant in Service	$6,059,395	Information not availiable
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	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

Mohegan Tribal Utility Authority

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.

			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]		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 @	$14,348.00	$3,306.00	$7,025.00		$4,017.00	Cost per acre based on verbal from Puul
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	
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	

Vendor	Invoice #	Component	Amount	Transmission	Distribution		Common	Comments
					Other	Transformer		
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 installation	$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	?03742		$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	

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

🟨 Shading denotes an input

Submitted on: May 16, 2011

Revenue Requirements for (year): Forecasted Fiscal Year 2011

Customer: Connecticut Transmission Municipal Elect

Customer's NABs Number: 51386

Name of Participant responsible for customer's billing: Connecticut Transmission Municipal Elect

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)	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)	0	(e)=(a)-(b)+(c)+(d)	0	(j)=(f)-(g)+(h)+(I)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Ru	0		7,378,334	(k)
Annual True-up (per Attachment C to Attachment F Imp	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:	7,378,334	(0) = (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)	7,378,334	(l)=(o)+(b)+(g)-(h)

CTMEEC
Connecticut Transmission Municipal Elect
For costs In 2011
FORECAST

🟨 Shading denotes an input

Line No,	I. FORECASTED TRANSMISSION REVENUE REQUIREMENTS	Period	POST-1996
1	Forecasted Transmission Plant Additions	2011	47,914,102
2	Carrying Charge Factor		15.40%
3	Total Forecasted Revenue Requirements (Lines 1*2)		**7,378,334**
	I. CARRYING CHARGE FACTOR		
4	Investment Return and Income Taxes		3,891,780
5	Depreciation Expense		1,175,104
6	Amortization of Loss on Reacquired Debt		0
7	Investment Tax Credit		0
8	Property Tax Expense		716,952
9	Payroll Tax Expense		0
10	Operation & Maintenance Expense		1,594,499
11	Administrative & General Expense		0
12	Total Expenses (Lines 4 thru 11)		7,378,335
13	PTF Transmission Plant		47,914,102
14	Carrying Charge Factor (Lines 12/13)		15.40%

Sheet: Input Panel

EFFECTIVE JUNE 1, 2011
ISO New England Inc.
Annual Transmission Revenue Requirements
Per FERC Electric Tariff No. 3, Section II - Attachment F

🟨 Shading denotes an input

Submitted on: 16-May-11

Revenue Requirements for (year): Calendar Year 2010

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

	Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I =	$204,508	(a)	$107,781	(f)
Total of Attachment F - Section J - Support Revenue	$0	(b)	$0	(g)
Total of Attachment F - Section K - Support Expense	$44,559	(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)	$249,067	(e)=(a)-(b)+(c)+(d)	$107,781	(j)=(f)-(g)+(h)+(i)
Forecasted Transmission Revenue Requirements (per Appendix C to Attachment F Implementation Rule)	N/A		$21,294	(m) Worksheet 1a
Annual True-up (per Appendix C to Attachment F Implementation Rule)	($59,943)	(k)	($21,281)	(n) Worksheet 1c
Interest Charge on Annual True-up	($1,997)	(l)	($709)	(o) Worksheet 1c
Total	$187,127	(p) =(e)+(k)+(l)	$107,085	(q)=(j)+(m)+(n)+(o)

Annual Revenue Requirements Total = Sum of Pre-97 Revenue Requirements & Post-96 Revenue Requirements Subtotals, Forecasted Revenue Requirements & True-ups (including interest) $294,212 (r) =(p)+(q)

Fitchburg Gas and Electric Light Company
Annual Revenue Requirements of PTF Facilities
for costs in 2010
PRE-1997

▨ Shading denotes an input

Line No.		Attachment F Reference	FG&E	Total	Reference
	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)	54,774	54,774	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)		1,299,422	1,299,422	
5	Accumulated Depreciation	(A)(1)(d)	578,341	578,341	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	287,550	287,550	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)	45,357	45,357	Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		478,888	478,888	
10	Prepayments	(A)(1)(h)	35,794	35,794	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	12,113	12,113	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	14,580	14,580	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		541,375	541,375	
	II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	65,161	65,161	Worksheet 2
15	Depreciation Expense	(B)	52,835	52,835	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)	13,172	13,172	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	1,256	1,256	*Worksheet 4, line 17 column 5*
20	Operation & Maintenance Expense	(G)	25,617	25,617	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	46,467	46,467	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)	44,559	44,559	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)		249,067	249,067	

Fitchburg Gas and Electric Light Company
Annual Revenue Requirements
for costs in 2010
PRE-1997

▨ Shading denotes an input

		CAPITALIZATION 12/31/10*	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	70,000,000	56.59%	6.99%	3.95%	
PREFERRED STOCK		1,736,060	1.40%	6.86%	0.10%	0.10%
COMMON EQUITY		51,955,368	42.00%	11.64%	4.89%	4.89%
TOTAL INVESTMENT RETURN	$	123,691,428	100.00%		8.94%	4.99%

*See Workpaper 2

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0894

(b) Federal Income Tax

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

$$= \frac{\left(0.0499 + (0 + 0) \;/\; 541{,}375 \right) \text{ x } 0.34)}{(1 - 0.34)}$$

= 0.0257061

(c) State Income Tax

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

$$= \frac{\left(0.0499 + (0 + 0) \;/\; 541{,}375 \right) + 0.0257061)^{*} \; 0.065}{(1 - 0.065)}$$

= 0.0052560

(a)+(b)+(c) **Cost of Capital Rate** = 0.1203621

		(PTF)	
INVESTMENT BASE	$	541,375	From Worksheet 1
x Cost of Capital Rate		0.1203621	
= Investment Return and Income Taxes		65,161	To Worksheet 1

Fitchburg Gas and Electric Light Company

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)
	Transmission Plant						
1	Transmission Plant			0		1,244,648	Line 1, Worksheet 5
2	General Plant	5,541,192	7.2527% (a)	401,886	13.6293%	54,774	Page 207.87g + (Page 201.3h + 201.6h - Total A/C 303 - Total A/C 310)*50.80% (d) (includes common plant)
3	Total (line 1+2)			401,886		1,299,422	
4	Transmission Plant Held for Future Use	0		0	13.6293%	0	Page 214
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	4,091,505		4,091,505	13.6293%	557,643	Page 219.25b
6	General Plant Accum.Depreciation	2,093,898	7.2527% (a)	151,864	13.6293%	20,698	Page 219.27c (includes common allocated to electric)
7	Total (line 5+6)			4,243,369		578,341	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	(24,758,838)	8.5574% (c)	(2,118,713)	13.6293%	(288,766)	Page 273.8k + 275.2k + 277.3k, See Workpaper 3
9	Accumulated Deferred Taxes (190)	104,276	8.5574% (c)	8,923	13.6293%	1,216	Page 234.8c
10	Total (line 8+9)			(2,109,790)		(287,550)	
11	Transmission loss on Reacquired Debt	0	8.5574% (c)	0	13.6293%	0	Page 111.81c
	Other Regulatory Assets						
12	FAS 106	1,026,042	7.2527% (a)	74,416	13.6293%	10,142	Page 232.13f.
13	FAS 109	3,019,315	8.5574% (c)	258,375	13.6293%	35,215	Page 232.1f - 278.1e
14	Other Regulatory Liabilities (254.DK)	0	8.5574% (c)	0	13.6293%	0	
15	Total (line 12+13+14)	4,045,357		332,791		45,357	
16	Transmission Prepayments	3,621,023	7.2527% (a)	262,622	13.6293%	35,794	Page 111.57c *p.200.8.c/p.200.8.b
17	Transmission Materials and Supplies	88,875		88,875	13.6293%	12,113	Page 227.8c
18	Cash Working Capital						
19	Operation & Maintenance Expense					25,617	Worksheet 1, Line 20
20	Administrative & General Expense					46,467	Worksheet 1, Line 21
21	Transmission Support Expense					44,559	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					116,643	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					14,580	

(a) Worksheet 5 of 8, line 11
(b) Worksheet 5 of 8, line 3
(c) Worksheet 5 of 8, line 16
(d) 50.80% is FGE's gas and electric labor allocator used for allocating common plant. See Workpaper 4.

Fitchburg Gas and Electric Light Company

PTF Revenue Requirements

Sheet: Worksheet 4

PRE-1997

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)
	Depreciation Expense						
1	Transmission Depreciation	373,981		373,981	13.6293%	50,971	Page 336.7b
2	General Depreciation	188,593	7.2527% (a)	13,678	13.6293%	1,864	Page 336.10b (includes common allocated to electric)
3	Total (line 1+2)			387,659		52,835	
4	Amortization of Loss on Reacquired Debt	0	8.5574% (c)	0	13.6293%	0	Page 117.64c
5	Amortization of Investment Tax Credits	0	8.5574% (c)	0	13.6293%	0	Page 266.8f
	Property Taxes						
6	Transmission Property Taxes	1,129,365	8.5574% (c)	96,644	13.6293%	13,172	Page 263i, lines 9, 10, 11 & 16
7	General Property Taxes	0	7.2527% (a)	0	13.6293%	0	Page 262-263
8	Total (line 6+7)			96,644		13,172	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	6,020,367		6,020,367	0.136293	820,534	Page 321.112b
10	Transmission of Electricity by Others - #565	5,678,371		5,678,371	0.136293	773,922	Page 321.96b
11	Load Dispatch & Scheduling - #561.0 to #561.4	154,045		154,045	0.136293	20,995	Page 321.84b
12	**Station Expenses & Rents - #562 / #567	0		0	0.136293	0	Page 321.85b & .90b
13	O&M less lines 10, 11 & 12	187,951		187,951	13.6293%	25,617	
	Transmission Administrative and General						
14	Administrative and General	4,776,944					Page 323.197b
15	*less Property Insurance (#924)*	*35,793*					*Page 323.185b*
16	*less Regulatory Commission Expenses (#928)*	*183,103*					*Page 323.189b*
17	*less General Advertising Expense (#930.1)*	*1,635*					*Page 323.191b*
18	Subtotal [line 14 minus (15 thru 17)]	4,556,413	7.2527% (a)	330,463	13.6293%	45,040	
19	***PLUS** Property Insurance alloc. using Plant Allocatior*	*35,793*	*8.5574% (c)*	3,063	13.6293%	417	
20	***PLUS** Regulatory Comm. Exp. (FERC Assessments - Transmission*	*7,409*		7,409	13.6293%	1,010	Page 351.6h
21	***PLUS** Trans. Related General Advertising Expense*	*0*	*8.5574% (c)*	0	13.6293%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*4,599,615*		*340,935*		*46,467*	
23	*Payroll Tax Expense*	*127,076*	*7.2527% (a)*	*9,216*	*13.6293%*	*1,256*	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	1,836		*Page 263.4i*
FICA	185,623		*Page 263.2i*
Medicare	0		
State Unemployment	4,789		*Page 263.6i*
MA Universal Health	0		*Page 263.8i*
Payroll Taxes Capitalized	(65,172)		*Page 263.15i*
Total	127,076	*To Line 23*	

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

PRE-1997

Sheet: Worksheet 5

🟨 Shading denotes an input

Line No.			FERC Form 1 Reference
	PTF Transmission Plant Allocation Factor	**FG&E**	
1	PTF Transmission Investment	1,244,648	See Workpaper 1
2	Total Transmission Investment	9,132,164	Page 207.58g
3	Percent Allocation (Line 1/Line 2)	13.6293%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	75,599	Page 354.21b
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 of 8
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	75,599	
7	Total Wages and Salaries	1,073,999	Page 354.28b + Line 5
8	Administrative and General Wages and Salaries	31,641	Page 354.27b
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)	1,042,358	
11	Percent Allocation (Line 6/Line 10)	7.2527%	
	Plant Allocation Factor		
12	Total Transmission Investment	9,132,164	Page 207.58g
13	*plus Transmission-Related General Plan (Line 2 of Wkst. 3)*	401,886	*Worksheet 3, Line 2, col.(3)*
14	*= Revised Numerator (Line 12 + Line 13)*	9,534,050	
15	Total Plant in Service	111,413,092	Page 207.95g + ((Page 201.3h + 201.6h - Total A/C 303 - Total A/C 310)*.5080) (a)
16	Percent Allocation (Line 14 / Line 15)	8.5574%	

(a) 50.80% is FGE's gas and electric labor allocator used for allocating common plant. See Workpaper 4.

Sheet: Worksheet 6

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		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	

PRE-1997

PTF Revenue Requirements
Worksheet 7 of 8

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.

		FG&E		TOTAL	
Participant	PTF Supporting Facilities	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	2,010	0	2,010
	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	12,431	0	12,431
	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	30,119	0	30,119
	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	44,559	0	44,559

Amount by which Support Expense exceeds Support Rev 44,559
(To Worksheet 3, Line 21, Column 5)

Sheet: Worksheet 8

RNS Rate
Workpaper 8 of 8

Summary of Fitchburg Gas and Electric Light Company System
Monthly Coincident Peaks for 2010
(Megawatts)
PRE-1997

🟨 Shading denotes an input

	JAN '10	FEB '10	MAR '10	APR '10	MAY '10	JUN '10	JUL '10	AUG '10	SEP '10	OCT '10	NOV '10	DEC '10
Day	13	3	3	28	26	28	6	31	1	27	30	9
Hour	18:00	19:00	19:00	21:00	17:00	14:00	17:00	17:00	17:00	19:00	18:00	18:00
FG&E	76	74	70	64	84	83	93	92	92	68	74	79

Annual FG&E System Average 12 CP Load **79**

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 2010
POST-1996

🟨 Shading denotes an input

Line No.		Attachment F Reference	Post-1996	Post-2003	Total	Reference
	I. INVESTMENT BASE	*Section:*				
1	Transmission Plant	(A)(1)(a)	658,110	538,550		Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	28,962	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)		687,072	538,550		
5	Accumulated Depreciation	(A)(1)(d)	305,798	250,244 (1)		Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	152,042	70,936 (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)	23,983	n/a		Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		253,215	217,370		
10	Prepayments	(A)(1)(h)	18,926	n/a		Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	6,405	n/a		Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	4,764	n/a		Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		283,310	217,370		
II.	REVENUE REQUIREMENTS					
14	Investment Return and Income Taxes	(A)	34,100	0 (3)	34,100	Worksheet 2, Worksheet 2a
15	Depreciation Expense	(B)	27,937		27,937	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)	6,965		6,965	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	664		664	*Worksheet 4, line 17 column 5*
20	Operation & Maintenance Expense	(G)	13,545		13,545	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	24,570		24,570	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)		107,781	0	107,781	

(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

Sheet: Worksheet 1a

POST-2003

Shading denotes an input

Line No.			Period	Attachment F Reference Section:	FG&E	Reference
	I.	FORECASTED TRANSMISSION REVENUE REQUIREMENTS				
1		Forecasted Transmission Plant Additions	2011	Appendix C	$130,024	Workpaper 1, Page 7
2		Carrying Charge Factor		Appendix C	16.38%	
3		Total Forecasted Revenue Requirements (Lines 1*2			$21,294	
	II.	CARRYING CHARGE FACTOR				
4		Investment Return and Income Taxes		(A)	$34,100	Worksheet 1, line 14
5		Depreciation Expense		(B)	$27,937	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)	$6,965	Worksheet 1, line 18
9		Payroll Tax Expense		(F)	$664	Worksheet 1, line 19
10		Operation & Maintenance Expense		(G)	$13,545	Worksheet 1, line 20
11		Administrative & General Expense		(H)	$24,570	Worksheet 1, line 21
12		Total Expenses (Lines 4 thru 11)			$107,781	
13		PTF Transmission Plant		(A)(1)(a)	$658,110	Worksheet 5, Line 1, Pre-2004 plus Post-2003
14		Carrying Charge Factor (Lines 12/13)			16.38%	

Fitchburg Gas and Electric Light Company

Transmission Revenue Requirements of PTF Facilities

2010 True-up

POST-2003

Sheet: Worksheet 1b

					FG&E		
	I.	ANNUAL TRUE-UP PER ATTACHMENT F	Period	Attachment F Reference *Section:*	Pre-97	Post 96	Reference
Line No.	1	Transmission Revenue Requirements (as billed)	6/10 - 5/11		$ 309,010	$ 129,062	ATRR - Prior Year
	2	True-up 2010 Actual Annual RR			$ 249,067	$ 107,781	Voting Share (e), (j)
	3	Over/(Under) (Line 1 - Line 2)			$ 59,943	$ 21,281	
	4	Over/(Under) June 1, 2010 - May 31, 2011			$ 59,943	$ 21,281	

Worksheet 1c

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

	Under / (Over)
PRE97	$ (59,943)
Post 1996	$ (21,281)

Initial Billing Period	PRE97 Balance	Post 1996 Balance	Monthly Interest Rate	PRE97 Interest	Post 1996 Interest
June 2010	$ (59,943)	$ (21,281)	0.27%	$ (162)	$ (57)
July 2010	$ (60,105)	$ (21,338)	0.28%	$ (168)	$ (60)
August 2010	$ (60,105)	$ (21,338)	0.28%	$ (168)	$ (60)
September 2010	$ (60,105)	$ (21,338)	0.27%	$ (162)	$ (58)
October 2010	$ (60,604)	$ (21,516)	0.28%	$ (170)	$ (60)
November 2010	$ (60,604)	$ (21,516)	0.27%	$ (164)	$ (58)
December 2010	$ (60,604)	$ (21,516)	0.28%	$ (170)	$ (60)
January 2011	$ (61,107)	$ (21,694)	0.28%	$ (171)	$ (61)
February 2011	$ (61,107)	$ (21,694)	0.25%	$ (153)	$ (54)
March 2011	$ (61,107)	$ (21,694)	0.28%	$ (171)	$ (61)
Apr-2011	$ (61,602)	$ (21,870)	0.27%	$ (166)	$ (59)
May-2011	$ (61,602)	$ (21,870)	0.28%	$ (172)	$ (61)
		Total Interest		$ (1,997)	$ (709)
		True-Up		$ (59,943)	$ (21,281)
		Total True-Up & Interest		**$ (61,940)**	**$ (21,990)**

Fitchburg Gas and Electric Light Company

Annual Revenue Requirements
for costs in 2010
POST-1996

▨ Shading denotes an input

		CAPITALIZATION 12/31/10*	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	70,000,000	56.59%	6.99%	3.95%	
PREFERRED STOCK	$	1,736,060	1.40%	6.86%	0.10%	0.10%
COMMON EQUITY	$	51,955,368	42.00%	11.64%	4.89%	4.89%
TOTAL INVESTMENT RETURN	$	123,691,428	100.00%		8.94%	4.99%

*See Workpaper 2

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0894

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

= (0.0499 +(0 + 0) / 283,310) x 0.34)
(1 - 0.34)

= 0.0257061

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)* State Income Tax Rate
(1 - State Income Tax Rate)

= (0.0499 +(0 + 0) / 283,310) + 0.0257061)* 0.065
(1 - 0.065)

= 0.0052560

(a)+(b)+(c) **Cost of Capital Rate** = 0.1203621

		(PTF)	
INVESTMENT BASE	$	283,310	From Worksheet 1, Line 13, Post-96
x Cost of Capital Rate		0.1203621	
= Investment Return and Income Taxes		34,100	To Worksheet 1

Sheet: Worksheet 3

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)
	Transmission Plant						
1	Transmission Plant			0		658,110	Line 1, Worksheet 5
							Page 207.99g + (Page 201.3h + 201.6h -
							Total A/C 303 - Total A/C 310)*50.80% (d)
2	General Plant	5,541,192	7.2527% (a)	401,886	7.2065%	28,962	(includes common plant)
3	Total (line 1+2)			401,886		687,072	
4	Transmission Plant Held for Future Use	0		0	7.2065%	0	Page 214
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	4,091,505		4,091,505	7.2065%	294,854	Page 219.25b
							Page 219.28c (includes common allocated
6	General Plant Accum.Depreciation	2,093,898	7.2527% (a)	151,864	7.2065%	10,944	to electric)
7	Total (line 5+6)			4,243,369		305,798	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	(24,758,838)	8.5574% (c)	(2,118,713)	7.2065%	(152,685)	Page 273.8k + 275.2k + 277.3k, See Workpaper 3
9	Accumulated Deferred Taxes (190)	104,276	8.5574% (c)	8,923	7.2065%	643	Page 234.8c
10	Total (line 8+9)			(2,109,790)		(152,042)	
11	Transmission loss on Reacquired Deb	0	8.5574% (c)	0	7.2065%	0	Page 111.81c
	Other Regulatory Assets						
12	FAS 106	1,026,042	7.2527% (a)	74,416	7.2065%	5,363	Page 232.16f
13	FAS 109	3,019,315	8.5574% (c)	258,375	7.2065%	18,620	Page 232.1f - 278.1f
14	Other Regulatory Liabilities (254.DK)	0	8.5574% (c)	0	7.2065%	0	
15	Total (line 12+13+14)	4,045,357		332,791		23,983	
16	Transmission Prepayments	3,621,023	7.2527% (a)	262,622	7.2065%	18,926	Page 111.57c *p.200.8.c/p.200.8.b
17	Transmission Materials and Supplies	88,875		88,875	7.2065%	6,405	Page 227.8c
18	Cash Working Capital						
19	Operation & Maintenance Expense					13,545	Worksheet 1, Line 20
20	Administrative & General Expense					24,570	Worksheet 1, Line 21
21	Transmission Support Expense					0	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					38,115	
23						0.125	x 45 / 360
24	Total (line 22 * line 23					4,764	

(a) Worksheet 5 of 8, line 11
(b) Worksheet 5 of 8, line 3
(c) Worksheet 5 of 8, line 16
(d) 50.80% is FGE's gas and electric labor allocator used for allocating common plant. See Workpaper 4.

Fitchburg Gas and Electric Light Company
PTF Revenue Requirements

Sheet: Worksheet 4

POST-1996

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)
	Depreciation Expense						
1	Transmission Depreciation	373,981		373,981	7.2065%	26,951	Page 336.7b
2	General Depreciation	188,593	7.2527% (a)	13,678	7.2065%	986	Page 336.10b (includes common allocated to electric)
3	Total (line 1+2)			387,659		27,937	
4	Amortization of Loss on Reacquired Debt	0	8.5574% (c)	0	7.2065%	0	Page 117.64c
5	Amortization of Investment Tax Credits	0	8.5574% (c)	0	7.2065%	0	Page 266.8f
	Property Taxes						
6	Transmission Property Taxes	1,129,365	8.5574% (c)	96,644	7.2065%	6,965	Page 263i, lines 9, 10, 11 & 16
7	General Property Taxes	0	7.2527% (a)	0	7.2065%	0	Page 262-263
8	Total (line 6+7)			96,644		6,965	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	6,020,367		6,020,367	7.2065%	433,858	Page 321.112b
10	Transmission of Electricity by Others - #565	5,678,371		5,678,371	7.2065%	409,212	Page 321.96b
11	Load Dispatch & Scheduling - #561.0 to #561.4	154,045		154,045	7.2065%	11,101	Page 321.84b to 321.88b
12	**Station Expenses & Rents - #562 / #567	0		0	7.2065%	0	Page 321.93b & .98b
13	O&M less lines 10, 11 & 12	187,951		187,951	7.2065%	13,545	
	Transmission Administrative and General						
14	Administrative and General	4,776,944					Page 323.197b
15	*less Property Insurance (#924)*	*35,793*					*Page 323.185b*
16	*less Regulatory Commission Expenses (#928)*	*183,103*					*Page 323.189b*
17	*less General Advertising Expense (#930.1)*	*1,635*					*Page 323.191b*
18	Subtotal [line 14 minus (15 thru 17)]	4,556,413	7.2527% (a)	330,463	7.2065%	23,815	
19	***PLUS** Property Insurance alloc. using Plant Allocator*	*35,793*	*8.5574% (c)*	3,063	7.2065%	221	
20	***PLUS** Regulatory Comm. Exp. (FERC Assessments - Transmission)*	*7,409*		7,409	7.2065%	534	Page 351.6h
21	***PLUS** Trans. Related General Advertising Expense*	*0*	*8.5574% (c)*	0	7.2065%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*4,599,615*		*340,935*		*24,570*	
23	*Payroll Tax Expense*	*127,076*	*7.2527% (a)*	*9,216*	*7.2065%*	*664*	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	1,836	*Page 263.4i*
FICA	185,623	*Page 263.2i*
Medicare	0	
State Unemployment	4,789	*Page 263.6i*
MA Universal Health	0	*Page 263.8i*
Payroll Taxes Capitalized	(65,172)	*Page 263.15i*
Total	127,076	*To Line 23*

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

POST-1996

Sheet: Worksheet 5

🟨 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	538,550	658,110	See Workpaper 1	
2	Total Transmission Investment	9,132,164	9,132,164	9,132,164	Page 207.58g	
3	Percent Allocation (Line 1/Line 2	1.3092%	5.8973%	7.2065%		1,902,758 20.8358%
	Transmission Wages and Salaries Allocation Factor					
4	Direct Transmission Wages and Salaries	75,599			Page 354.21b	
5	Affiliated Company Transmission Wages and Salaries	0			Worksheet 6 of 8	
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	75,599				
7	Total Wages and Salaries	1,073,999			Page 354.28b + Line 5	
8	Administrative and General Wages and Salaries	31,641			Page 354.27b	
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)	1,042,358				
11	Percent Allocation (Line 6/Line 10	7.2527%				
	Plant Allocation Factor					
12	Total Transmission Investment	9,132,164			Page 207.58g	
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	401,886			*Worksheet 3, Line 2, col.(3)*	
14	*= Revised Numerator (Line 12 + Line 13)*	9,534,050				
15	Total Plant in Service	111,413,092			Page 207.104g + ((Page 201.3h + 201.6h - Total A/C 303 - Tota A/C 310)*.5080) (a)	
16	Percent Allocation (Line 14 / Line 15	8.5574%				

(a) 50.80% is FGE's gas and electric labor allocator used for allocating common plant. See Workpaper 4.

Sheet: Worksheet 6

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		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.

		FG&E		TOTAL	
Participant	PTF Supporting Facilities	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

Amount by which Support Expense exceeds Support Revenue 0
(To Worksheet 3, Line 21, Column 5)

Summary of **Fitchburg Gas and Electric Light Company** System
Monthly Coincident Peaks for 2010
(Megawatts)
POST-1996

🟨 Shading denotes an input

	JAN '10	FEB '10	MAR '10	APR '10	MAY '10	JUN '10	JUL '10	AUG '10	SEP '10	OCT '10	NOV '10	DEC '10
Day	13	3	3	28	26	28	6	31	1	27	30	9
Hour	18:00	19:00	19:00	21:00	17:00	14:00	17:00	17:00	17:00	19:00	18:00	18:00
FG&E	76	74	70	64	84	83	93	92	92	68	74	79

Annual FG&E System Average 12 CP Load **79**

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

Workpaper 1
Detail of PTF Transmission Plant as of 12/31/09

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

Date	Description	In Service	Value	Classification	PTF 1	Non-PTF 2	PTF XMFR 3	Non-PTF XMFR 4	Common 5
Land									
Apr-94	Fused Disconnec	1977	(505.26)	5	0	0	0	0	-505.26
May-94	Replace Fused Disconnec		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		0.00	2	0	0	0	0	0
	in place of failed #1 autotrans.		237,601.84	2	0	237601.84	0	0	0
	Repair and rewind of 115-69 KV #1 Autotransformer		0.00	3	0	0	0	0	0
	including uprating to a rated capacity of 60/80/100 MVA		335,776.00	4	0	0	0	335776	0
	Insurance Recovery less deductible of $25K		(321,696.66)	4	0	0	0	-321696.66	0
Nov-95	Lightning arrestors, delivery and testing		6,840.09	2	0	6840.09	0	0	0
Sep-96	60/80/100 MVA 115-69kV Autotransformer (1996) S/N=MNL9258		544,772.08	4	0	0	0	544772.08	0
Sep-96	Installation cost for above (1996)		42,610.39	4	0	0	0	42610.39	0
Nov-97	Current Transformers	1977	(8,000.00)	5	0	0	0	0	-8000
Mar-98	Autotransformer Disconnect Switch	1977	(2,700.00)	2	0	-2700	0	0	0
May-98	D-30 Oil Circuit Breaker	1977	(14,590.00)	2	0	-14590	0	0	0
May-98	Disconnect Switch for above	1977	(2,700.00)	2	0	-2700	0	0	0
	C29 Breaker Disconnect Switch	1977	(5,858.61)	2	0	-5858.61	0	0	0
Aug-00	Three Phase overcurrent relays	1977	(2,100.00)	2	0	-2100	0	0	0
	Ground overcurrent relays	1977	(1,400.00)	2	0	-1400	0	0	0
Nov-05	Retire Meters & Relays, Control Power System	1978	(25,490.00)	1	-25490	0	0	0	0
Nov-05	Retire Ann. & events Recorder, Rochester Instrument #449-1462	1978	(15,400.00)	1	-15400	0	0	0	0
Nov-05	Retire 200 Ampere Hour Battery, Excide	1978	(3,042.00)	1	-3042	0	0	0	0
Nov-05	Retire Engineering Services and Testing Service	1978	(11,269.53)	1	-11269.53	0	0	0	0
Nov-05	Retire Antenna Installed	1978	(302.00)	1	-302	0	0	0	0
Nov-05	Retire Encoders Installed	1978	(547.00)	1	-547	0	0	0	0
Nov-05	Retire AC Power Surge Kit	1978	(21.00)	1	-21	0	0	0	0
Nov-05	Retire Coaxial Antenna, Lead, Fittings & Installation of Antenn	1978	(261.35)	1	-261.35	0	0	0	0
Nov-05	Retire BBA15-AA11 Desk Top 50 Watt #6161 4030A	1978	(1,195.00)	1	-1195	0	0	0	0
Nov-05	Retire B169 AC Power Surge Kit MI 559429	1978	(21.00)	1	-21	0	0	0	0
Nov-05	Retire Sales Tax on Above	1978	(10.03)	1	-10.03	0	0	0	0
Nov-05	Retire Cleverdon, Varney & Pike Invoices	1978	(14,094.12)	1	-14094.12	0	0	0	0
Nov-05	Retire Cleverdon, Varney & Pike Engineering Services Invoice	1978	(9,047.75)	1	-9047.75	0	0	0	0
Nov-05	Retire General Electric Company Invoices for computer services	1978	(76.19)	1	-76.19	0	0	0	0
Nov-05	Retire Events Recorder & Accessories (from Rochester Instruments)	1978	(69.24)	1	-69.24	0	0	0	0
Nov-05	Retire Metering	1984	(20,742.26)	1	-20742.26	0	0	0	0
Nov-05	Retire 'Watt/Var Transducer	Aug-90	(5,950.00)	5	0	0	0	0	-5950
Nov-05	Retire Vollt Transducer	Aug-90	(185.00)	5	0	0	0	0	-185
Nov-05	Retire Shipping & Handling	Aug-90	(34.92)	5	0	0	0	0	-34.92
Nov-05	Labor for fixing recorder	Aug-90	(368.80)	5	0	0	0	0	-368.8
Nov-05	Labor for wiring	Aug-90	(124.20)	5	0	0	0	0	-124.2
Nov-05	Retire 'Install GETEC Telemetering to REMVAC (Liabilities)	Aug-90	(422.31)	5	0	0	0	0	-422.31
Nov-05	Retire Overheads	Aug-90	(6,638.54)	5	0	0	0	0	-6638.54
Nov-05	Retire 'Payroll	Aug-90	(8,030.61)	5	0	0	0	0	-8030.61
Nov-05	Retire Duct Tone Receivers Installed	1978	($447.00)	1	-447	0	0	0	0
Nov-05	Retire B166 Emergency Power Option #CT 1009-0	1978	($102.00)	1	-102	0	0	0	0
Nov-05	Retire Data Star Recorders	Feb-87	(3,780.00)	5	0	0	0	0	-3780
Nov-05	Retire Installed Data Ster REcorder Software Level #2	Mar-87	(750.00)	5	0	0	0	0	-750
Nov-05	Retire Payroll & overheads for above instal	1987	(1,014.38)	5	0	0	0	0	-1014.38
Nov-05	Retire 500' 4/C #12 AWG Control Cable	Aug-90	(1,142.10)	5	0	0	0	0	-1142.1
Nov-05	Retire 50' 1/2 watt precision resistors	Aug-90	(41.39)	5	0	0	0	0	-41.39
Nov-05	Retire 350' T&B Stakon Terminals	Aug-90	(86.45)	5	0	0	0	0	-86.45
Nov-05	Retire 69' Copper Wire	Aug-90	(10.35)	5	0	0	0	0	-10.35
Nov-05	Retire Cable Tie	Aug-90	(17.55)	5	0	0	0	0	-17.55
Nov-05	Retire Misc Parts	Aug-90	(52.76)	5	0	0	0	0	-52.76
Nov-05	Retire 'Bristol DPC 333010A computer	Aug-90	(4,230.71)	5	0	0	0	0	-4230.71
Nov-05	Retire Bristol SLC 371140A Recorders	Aug-90	(5,771.41)	5	0	0	0	0	-5771.41
Nov-05	Retire Bristol Power Supply	Aug-90	(515.05)	5	0	0	0	0	-515.05
Nov-05	Retire Labor to set up Bristol	Aug-90	(2,355.00)	5	0	0	0	0	-2355
Dec-06	Retired used Auto Transformer 24/40 mva Magntek	1992	(200,032.04)	4	0	0	0	-200,032.04	0
Jul-08	Retire Deadend Structure 3-arrestors & 6-bushings	1994	(30,233.66)	5	0	0	0	0	-30233.66
Total Pre-97 PTF			3,259,541.37		1,202,389.70	598,768.91	0	1,377,877.70	80,505.06

						PTF	Non-PTF	PTF XMFR	Non-PTF XMFR	Common
Date	Description		In Service	Value	Classification	1	2	3	4	5
Land										
Nov-97	69kv Post Insulators			7,125.43	2	0	7125.43	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 Autc			1,990.46	2	0	1990.46	0	0	0
Mar-98	Repl Autotransformer 69kv Disconnect Switches			14,416.88	2	0	14416.88	0	0	0
Apr-98	Additional charges for above			3,799.62	2	0	3799.62	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
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
Dec-99	UV Relay installec			605.13	2	0	605.13	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
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
Aug-00	Additional charges for modifications for 3rd line			9,717.74	2	0	9717.74	0	0	0
Oct-02	Replace #5 Bushing on 7A1 Oil Circuit Breake			7,705.53	2	0	7705.53	0	0	0
Nov-02	Install Spare PT s/n 1024577			26,749.83	2	0	26749.83	0	0	0
Nov-02	Purchase spare PT JVZ350VT 350/600 s/n 1890057484			9,479.40	2	0	9479.4	0	0	0
Feb-03	Installation cost for Spare Bushing #5 (C-9293)			7,268.29	2	0	7268.29	0	0	0
Mar-03	Cable Trenches and Conduit for new Control Hous			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 Installec		Dec-99	(605.13)	2	0	-605.13	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
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 chg:		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 Insulato			529.89	2	0	529.89	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
Mar-10	Labor and Materials to upgrade and withstand additional load related to NGrid 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
Total Post-03 PTF				$2,183,358.38		$538,549.61	$654,069.26	$0.00	$990,739.51	$0.00
PTF		1,740,939.31		$ 5,993,487.95		$ 1,740,939.31	$ 1,575,656.39	$ -	$ 2,368,617.21	$ 308,275.04
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	42,259	COMMON POST-96 PTF	119,560
Total Pre-97PTF	1,244,648	Total POST-96 PTF	119,560

POST-03 PTF	538,550
XFRM POST-03 PTF	-
COMMON POST-03 PTF	-
Total POST-03 PTF	538,550

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

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
	Control House (PTF)	$438,483.13	

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

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	**69 kv portion of SCADA Equipment**		
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	**69 kv portion Installation of Control House, etc.**		
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	$1,676.13	2
	Control House (Non-PTF)	$574,504.78	
	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	11,457.33	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	11,457.32	2
	Yard Lighting (Non-PTF)	21,239.41	
	Total Yard Lighting Cost	42,478.87	

Fitchburg Gas and Electric Light Compan
2011 Estimated PTF Plant Addition

Date	Description	Value	Classificatior	PTF 1	Non-PTF 2	PTF XMFR 3	Non-PTF XMFR 4	Common 5
Post 2005								
Est. 2011	Flagg Pond Substation - Modify CT Wiring	$43,690	1	$43,690	0	0	0	0
Est. 2011	I135N Line Relaying - Fitzwilliam Project	$86,334	1	$86,334	$0	$0	$0	$0
Total		$130,024		$130,024	$0	$0	$0	$0
PTF Ratio (See page 3								52.49%
PTF Estimated Additions								$130,024

WORKPAPER 2

Fitchburg Gas and Electric Light Company

2010 Cost of Capital

	Amount Outstanding 12/31/10	*C.O.C.*	*Weight*	*Weighted Cost of Capital*
Common Stock Equity	$51,955,368	11.64%	42.00%	4.89%
Preferred Stock	1,736,060	6.86%	1.40%	0.10%
Long Term Debt (include. due in 1 yr.)	70,000,000	6.99%	56.59%	3.95%
Total	$123,691,428			8.94%

Common Equity

Common Stock	$22,627,257
Retained Earnings	9,863,434
Capital Stock Expense	(1,535,323)
Misc. Paid in Capital	21,000,000
Total	$51,955,368

Preferred Stock $100 Par

Series		*Amount Outstanding 12/31/10*	*Annual Issuance Expense*	*Annual Dividend Expense*	*Total Annual Cost*	*Effective Cost %*
5.125%		$790,100	$226	$40,750	$40,976	5.19%
8.00%		974,200	97	78,034	78,131	8.02%
		$1,764,300	$323	$118,784	$119,107	6.75%
Less: Capital Stock Expense	5.125%	$8,872				
	8.00%	19,368				
	Subtotal	$28,240				
Total		1,736,060				6.86%

Long Term Debt

Series		*Amount Outstanding 12/31/10*	*Annual Issuance Expense*	*Annual Interest Expense*	*Total Annual Cost*	*Effective Cost %*
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

			2010	
1. Account 281	Accumulated Deferred Income Taxes - Accelerated Amortization Property	$	-	FF1, Page 273.8k
2. Account 282	Accumulated Deferred Income Taxes - Other Property	$	17,673,650	FF1, Page 275.2k
3. Account 283	Account 283 - Electric	$	(800,407)	FF1, Page 277.3k
4. Account 283	Less FAS 106 OPEB	$	(1,290,285)	
5. Account 283	Less FAS 158	$	(6,595,310)	
		$	24,758,838	Worksheet 3, Line 8

Detail for Lines 4 and 5. Source: accounting records.	Electric		Gas		Total	
Def FIT FAS 158 SERP	$	(288,970)	$	(286,200)	$	(575,170)
Def SIT FAS 158 SERP	$	(78,955)	$	(78,198)	$	(157,154)
Def FIT FAS 158 Pension	$	(3,377,903)	$	(3,294,141)	$	(6,672,044)
Def SIT FAS 158 Pension	$	(752,973)	$	(735,462)	$	(1,488,435)
Def FIT FAS 158 PBOP	$	(1,702,159)	$	(1,670,654)	$	(3,372,813)
Def SIT FAS 158 PBOP	$	(394,350)	$	(387,970)	$	(782,320)
Total FAS 158	$	(6,595,310)	$	(6,452,625)	$	(13,047,936)
Def FIT FAS 106 OPEB	$	(1,095,447)	$	(1,011,808)	$	(2,107,255)
Def SIT FAS 106 OPEB	$	(194,838)	$	(234,904)	$	(429,742)
Total FAS 106 OPEB	$	(1,290,285)	$	(1,246,712)	$	(2,536,997)

Workpaper 4
Fitchburg Gas and Electric Light Company
Labor Allocator
2009 percentages applicable to 2010 costs

		Gas	Electric	Total
Salaries & Wages - Operation & Maintenance				
	Production - Maint	$ 73,142		$ 73,142
	Production - Oper	316,652		316,652
	Transmission - Maint		43,287	43,287
	Transmission - Oper	64,472	50,246	114,717
	Distribution - Maint	210,635	279,521	490,156
	Distribution - Oper	681,182	529,751	1,210,933
	Customer Accounting	47,635	68,924	116,559
	Admin & General	-	-	-
	Total - O&M Direct Labor	**1,393,718**	**971,728**	**2,365,446**
Construction				
	Direct Payrol	149,488	677,346	826,833
	Overhead Payrol	310,227	264,797	575,024
	Total - Construction Direct Labor	**459,714**	**942,143**	**1,401,857**
	Total Direct Labor	**$ 1,853,433**	**$ 1,913,870**	**$ 3,767,303**
	Labor Allocator	**49.20%**	**50.80%**	**100.00%**

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

			2010	
Account 281	Accumulated Deferred Income Taxes - Accelerated Amortization Property	$	-	FF1, Page 273.8k
Account 282	Accumulated Deferred Income Taxes - Other Property	$	17,673,650	FF1, Page 275.2k
	Total Accounts 281, 282	$	17,673,650	
	Plant Allocation Factor		8.5574%	Worksheet 5, Line 16
	Transmission Allocated (Total Accounts 281, 282 * Plant Allocation Factor)	$	1,512,405	
	Post-2003 PTF Transmission Plant Allocation Factor		5.8973%	Worksheet 5, Line 3 - Column 2
	Post-2003 PTF Accumulated Deferred Income Tax	$	89,191	Worksheet 1, Line 6

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

			2010	
20-20-13-00-565-75-00	BECO HQII - TRANSMISSION	$	2,010	Worksheet 7, BECo HQ Phase II - AC in MA
20-20-13-00-565-76-00	NEP HQII - TRANSMISSION	$	30,119	Worksheet 7, NEP HQ Phase II - AC in MA

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

2010 ACTUAL CHESTER SVC COSTS	$	2,863,560

SUPPORTER	SUPPORTER SHARE			
Fitchburg Gas and Electric Light Company	0.4341%	$	12,431	(1)

(1) Worksheet 7, NEP Chester SVC.
FG&E's accounting records do not provide sufficient level of detail. Data provided by NEP

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: 17-May-11

Revenue Requirements for (year): Calendar Year 2010

Rates Effective for the period: June 2011
through: May 2012

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	=	949,116	(a)	496,235	(f)
Total of Attachment F - Section J - Support Revenue		0	(b)	0	(g)
Total of Attachment F - Section K - Support Expense		44,074	(c)	0	(h)
Total of Attachment F - Section (L through O)		(1,080)	(d)	0	(i)
Sub Total - Sum (A through I) - J + K + (L through O)		992,109	(e)=(a)-(b)+(c)+(d)	496,235	(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)		N/A		13,679	(k)
Annual True-up (per Attachment C to Attachment F Implementation Rule)		(127,401)	(l)	(56,172)	(m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)		864,708	(n)=(e)+(l)	453,742	(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)				1,318,450	(p)=(n)+(o)

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

			Pre 1997	**Post 1996**	
1 2010 Est. Transmission Revenue Requirements (as billec	6/10-05/11	Appendix C	1,115,463	550,623	ATRR - Prior Year
2 2010 Actual Annual RR			992,109	496,235	Input Panel Subtotals
3 True-up Over/(Under) (Line 1 - Line 2)			123,354	54,388	

	Undercollection / (Overcollection)
PRE97	(123,354)
Post1996	($54,388)

Initial Billing Period	PRE97 Balance	POST 1996 Balance	FERC Monthly Interest Rate	PRE97 Interest	POST 1996 Interest
June 2010	$ (123,354)	(54,388)	0.27%	$ (333)	$ (147)
July 2010	$ (123,687)	(54,535)	0.27%	(334)	(147)
August 2010	$ (123,687)	(54,535)	0.27%	(334)	(147)
September 2010	$ (123,687)	(54,535)	0.27%	(334)	(147)
October 2010	$ (124,688)	(54,976)	0.27%	(337)	(148)
November 2010	$ (124,688)	(54,976)	0.27%	(337)	(148)
December 2010	$ (124,688)	(54,976)	0.27%	(337)	(148)
January 2011	$ (125,698)	(55,422)	0.27%	(339)	(150)
February 2011	$ (125,698)	(55,422)	0.27%	(339)	(150)
March 2011	$ (125,698)	(55,422)	0.27%	(339)	(150)
April 2011	$ (126,717)	(55,871)	0.27%	(342)	(151)
May 2011	$ (126,717)	(55,871)	0.27%	(342)	(151)
		Total Interest		**$ (4,047)**	**$ (1,785)**
		True-Up		(123,353.57)	($54,388)
		Total TU & Int		$ (127,401)	$ (56,172)

Sheet: Forecast

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

POST-1996

▨ Shading denotes an input

Line No.		Period	Attachment F Reference *Section:*	**HG&E**	Reference
	I. FORECASTED TRANSMISSION REVENUE REQUIREMENTS				
1	Forecasted Transmission Plant Additions	2011	Appendix C	$62,500	
2	Carrying Charge Factor		Appendix C	21.89%	
3	Total Forecasted Revenue Requirements (Lines 1*2)			$13,679	
	II. CARRYING CHARGE FACTOR				
4	Investment Return and Income Taxes		(A)	$134,731	Worksheet 1a, line 14
5	Depreciation Expense		(B)	$40,526	Summary, line 15
6	Amortization of Loss on Reacquired Debt		(C)	$12,553	Summary, line 16
7	Investment Tax Credit		(D)	$0	Summary, line 17
8	Property Tax Expense		(E)	$33,167	Summary, line 18
9	Payroll Tax Expense		(F)	$809	Summary, line 19
10	Operation & Maintenance Expense		(G)	$165,293	Summary, line 20
11	Administrative & General Expense		(H)	$109,156	Summary, line 21
12	Total Expenses (Lines 4 thru 11)			$496,235	
13	PTF Transmission Plant		(A)(1)(a)	$2,267,299	Summary, line 1
14	Carrying Charge Factor (Lines 12/13)			21.89%	

Sheet: Summary 0609-0510

Holyoke Gas & Electric Department
Annual Revenue Requirements of pre-1997 & post-1996 PTF
for costs as billed in 2010 06/10-05/11

Line No.		Attachment F Reference	Pre 1997	Post 1996	Reference
	I. INVESTMENT BASE	*Section:*			
1	Transmission Plant	(A)(1)(a)	4,271,276	2,093,511	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	248,971	122,030	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)		4,520,247	2,215,541	
5	Accumulated Depreciation	(A)(1)(d)	2,812,981	1,378,745	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)	79,817	39,121	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)		1,787,083	875,917	
10	Prepayments	(A)(1)(h)	1,353,678	663,487	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	75,831	37,167	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	74,598	33,913	Worksheet 3, line 23 column 5
				0	
13	Total Investment Base (Line 9+10+11+12)		3,291,190	1,610,484	
II.	REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	279,751	136,891	Worksheet 2
15	Depreciation Expense	(B)	78,269	38,362	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	79,817	39,121	Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)	0	0	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	61,197	29,995	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	1,360	667	*Worksheet 4, line 17 column 5*
20	Operation & Maintenance Expense	(G)	339,889	166,592	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	213,638	104,712	Worksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0	0	Worksheet 7
22a	Share of Seabrook Transmission Revenue Requirement		18,974	0	From MMWEC Analysis of Holyoke's % Share
23	Transmission Support Revenue	(J)	0	0	Worksheet 7
24	Transmission Support Expense	(K)	43,255	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)	(241)	0	NEPOOL Sch 1: ST Through and Out Revenues (TOUT Sch 1)
28	Transmission Rents Received from Electric Property	(O)	(446)	0	Page 37 line 18b * Actual number of Transmission poles
29	Total Revenue Requirements (Line 14 thru 28)		1,115,463	516,340	

▨ Shading denotes an input

Line No.		Attachment F Reference Section:	Holyoke	Reference
	I. INVESTMENT BASE			
1	Transmission Plant	(A)(1)(a)	4,271,276	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	254,738	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)		4,526,014	
5	Accumulated Depreciation	(A)(1)(d)	2,828,580	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)	23,649	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)		1,721,083	
10	Prepayments	(A)(1)(h)	1,139,447	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	60,884	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	70,137	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		2,991,551	
	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	254,282	Worksheet 2
15	Depreciation Expense	(B)	76,345	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	23,649	Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)	0	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	62,483	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	1,524	*Worksheet 4, line 17 column 5*
20	Operation & Maintenance Expense	(G)	311,388	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	205,635	Worksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7
22a	Share of Seabrook Transmission Revenue Requirement		13,810	From MMWEC Analysis of Holyoke's % Share
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	44,074	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)	(636)	NEPOOL Sch 1: ST Through and Out Revenues (T
28	Transmission Rents Received from Electric Property	(O)	(444)	Page 37 line 18b * Actual number of Trans
29	Total Revenue Requirements (Line 14 thru 28)		992,109	

🟨 Shading denotes an input

Line No.		Attachment F Reference	**Holyoke**	Reference
	I. INVESTMENT BASE	*Section:*		
1	Transmission Plant	(A)(1)(a)	2,267,299	Worksheet 3a, line 1 column 5
2	General Plant	(A)(1)(b)	135,221	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)		2,402,520	
5	Accumulated Depreciation	(A)(1)(d)	1,501,481	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)	12,553	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)		913,592	
10	Prepayments	(A)(1)(h)	604,847	Worksheet 3a, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	32,319	Worksheet 3a, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	34,306	Worksheet 3a, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		1,585,064	
	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	134,731	Worksheet 2a
15	Depreciation Expense	(B)	40,526	Worksheet 4a, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	12,553	Worksheet 4a, line 4 column 5
17	Investment Tax Credit	(D)	0	Worksheet 4a, line 5 column 5
18	Property Tax Expense	(E)	33,167	Worksheet 4a, line 8 column 5
19	Payroll Tax Expense	(F)	809	*Worksheet 4a, line 17 column 5*
20	Operation & Maintenance Expense	(G)	165,293	Worksheet 4a, line 13 column 5
21	Administrative & General Expense	(H)	109,156	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)		496,235	

Holyoke Gas & Electric Department

Annual Revenue Requirements
for costs in 2010
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!		#VALUE!	#VALUE!
TOTAL INVESTMENT RETURN	$	n/a	#VALUE!		#VALUE!	#VALUE!

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0850 **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 = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

= (0.0000 +(0 + 0) / 2,991,551) x 0)
(1 - 0)

= 0.0000000

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)* State Income Tax Rate
(1 - State Income Tax Rate)

= (0.0000 +(0 + 0) / 2,991,551) + 0.0000000)* 0
(1 - 0)

= 0.0000000

(a)+(b)+(c) **Cost of Capital Rate** = 0.0850000

		(PTF)	
INVESTMENT BASE	$	2,991,551	From Worksheet 1
x Cost of Capital Rate		0.0850000	
= Investment Return and Income Taxes		254,282	To Worksheet 1

Holyoke Gas & Electric Department

Annual Revenue Requirements
for costs in 2010
Post-1996

▨ 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 = 0.085 to 0.095

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 include

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

= (0.0000 +(0 + 0) / 2,991,551) x 0)
(1 - 0)

= 0.0000000

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)* State Income Tax Rate
(1 - State Income Tax Rate)

= (0.0000 +(0 + 0) / 2,991,551) + 0.0000000)* 0
(1 - 0)

= 0.0000000

(a)+(b)+(c) **Cost of Capital Rate** = #VALUE!

		(PTF) prior 1/1/04		**(PTF) on or after 1/1/04**		**(PTF) on or after 1/1/04**	
INVESTMENT BASE	$	1,585,064	From Worksheet 1	1,585,064	From Worksheet 1	1,585,064	From Worksheet 1
% Allocated to respective period		0.31%		99.69%		0.00%	
PERIOD INVESTMENT BASE		4,926		1,580,138		0	
x Cost of Capital Rate		0.0850000		0.0850000	Not included in RSP	0.0950000	Included in RSP
= Investment Return and Income Taxes		419	To Worksheet 1	134,312	To Worksheet 1	0	To Worksheet 1

Holyoke Gas & Electric Department

Pre-1997

Sheet: Worksheet 3

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)
	Transmission Plant						
1	Transmission Plant	8,458,844		8,458,844		4,271,276	Line 1, Worksheet 5
2	General Plant	7,563,127	6.6703% (a)	504,483	50.4948%	254,738	Page 8B, line 30g less line 29 telecom
3	Total (line 1+2)			8,963,327		4,526,014	
4	Transmission Plant Held for Future Use	0		0	50.4948%	0	None known
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	5,252,809		5,252,809	50.4948%	2,652,395	Page 8A, line 31g less Page 16, line 31g
6	General Plant Accum.Depreciation	5,230,902	6.6703% (a)	348,917	50.4948%	176,185	(Page 8B, line 30g less line29 telecom) less (Page 17, line 30g less line 29g telecom)
7	Total (line 5+6)			5,601,726		2,828,580	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	0	7.2351% (c)	0	50.4948%	0	None known
9	Accumulated Deferred Taxes (190)	0	7.2351% (c)	0	50.4948%	0	None known
10	Total (line 8+9)			0		0	
11	Transmission loss on Reacquired Debt	647,322	7.2351% (c)	46,834	50.4948%	23,649	Page 13, line 28d
	Other Regulatory Assets						
12	FAS 106	0	6.6703% (a)	0	50.4948%	0	None known
13	FAS 109	0	7.2351% (c)	0	50.4948%	0	None known
14	Other Regulatory Liabilities (254.DK)	0	7.2351% (c)	0	50.4948%	0	
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments	33,830,022	6.6703% (a)	2,256,564	50.4948%	1,139,447	Page 10, line 26c
17	Transmission Materials and Supplies	1,666,520	7.2351% (a)	120,574	50.4948%	60,884	Page 14, line 16b
			Per Guidance Document I. R. Section II.A.1 as well as Application of I. R. to MTO's				
18	Cash Working Capital						
19	Operation & Maintenance Expense					311,388	Worksheet 1, Line 20
20	Administrative & General Expense					205,635	Worksheet 1, Line 21
21	Transmission Support Expense					44,074	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					561,097	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					70,137	

(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

Post-1996

PTF Revenue Requirements
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)
	Transmission Plant						
1	Transmission Plant	8,458,844		8,458,844		2,267,299	Line 1, Worksheet 5
2	General Plant	7,563,127	6.6703% (a)	504,483	26.8039%	135,221	Page 8B, line 30g less line 29 telecom
3	Total (line 1+2)			8,963,327		2,402,520	
4	Transmission Plant Held for Future Use	0		0	26.8039%	0	None known
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	5,252,809		5,252,809	26.8039%	1,407,958	Page 8A, line 31g less Page 16, line 31g
6	General Plant Accum.Depreciation	5,230,902	6.6703% (a)	348,917	26.8039%	93,523	(Page 8B, line 30g less line29 telecom) less (Page 17, line 30g less line 29g telecom)
7	Total (line 5+6)			5,601,726		1,501,481	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	0	7.2351% (c)	0	26.8039%	0	None known
9	Accumulated Deferred Taxes (190)	0	7.2351% (c)	0	26.8039%	0	None known
10	Total (line 8+9)			0		0	
11	Transmission loss on Reacquired Debt	647,322	7.2351% (c)	46,834	26.8039%	12,553	Page 12, line 28b
	Other Regulatory Assets						
12	FAS 106	0	6.6703% (a)	0	26.8039%	0	None known
13	FAS 109	0	7.2351% (c)	0	26.8039%	0	None known
14	Other Regulatory Liabilities (254.DK)	0	7.2351% (c)	0	26.8039%	0	
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments	33,830,022	6.6703% (a)	2,256,564	26.8039%	604,847	Page 10, line 26c
17	Transmission Materials and Supplies	1,666,520	7.2351% (a)	120,574	26.8039%	32,319	Page 14, line 16b
			Per Guidance Document I. R. Section II.A.1 as well as Application of I. R. to MTO's				
18	Cash Working Capital						
19	Operation & Maintenance Expense					165,293	Worksheet 41a, Line 20
20	Administrative & General Expense					109,156	Worksheet 41a, Line 21
21	Transmission Support Expense					0	Worksheet 41a, Line 24
22	Subtotal (line 19+20+21)					274,449	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					34,306	

(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

Sheet: Worksheet 4

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	Transmission Depreciation	129,897		129,897	50.4948%	65,591	Page 16, line 31d
2	General Depreciation	319,302	6.6703% (a)	21,298	50.4948%	10,754	Page 17, line 30d less line 29 Telecom
3	Total (line 1+2)			151,195		76,345	
4	Amortization of Loss on Reacquired Debt	647,322	7.2351% (c)	46,834	50.4948%	23,649	Page 13, line 28d
5	Amortization of Investment Tax Credits	0	7.2351% (c)	0	50.4948%	0	None known
	Property Taxes *						
6	Transmission Property Taxes	118,014		118,014	50.4948%	59,591	See below
7	General Property Taxes	85,849	6.6703% (a)	5,726	50.4948%	2,892	
8	Total (line 6+7)			123,741		62,483	
	Transmission Operation and Maintenance	PER INTERPRETATIVE GUIDANCE DOCUMENT SECTION II.G RULES FOR HGED					
9	Operation and Maintenance	3,249,661		3,249,661	50.4948%	1,640,910	Page 40, line 50b
10	Transmission of Electricity by Others - #565	2,632,987		2,632,987	50.4948%	1,329,522	Page 40, line 38b
11	Load Dispatching - #561	0		0	50.4948%	0	Page 40, line 34b
12	**Station Expenses & Rents - #562 / #567					0	Page 40, line 35b, 40b only if include Support
13	O&M less lines 10, 11 & 12	616,674		616,674	50.4948%	311,388	
	Transmission Administrative and General						
14	Administrative and General	6,139,073					Page 42, line 7b less line 5b, less pg 41 line 56b telecom
15	*less Property Insurance (#924)*	*443,881*					*Page 41, line 49b*
16	*less Regulatory Commission Expenses (#928)*	*0*					*Page 41, line 52b*
17	*less General Advertising Expense (#930.1)*	*71,382*					*G/L Acct 930-03 Public Goodwill less in Lieu of Discounts & Fiber Optic Cable*
18	Subtotal [line 14 minus (15 thru 17)	5,623,810	6.6703% (a)	375,125	50.4948%	189,419	
19	*PLUS Property Insurance alloc. using Plant Allocation*	*443,881*	*7.2351% (c)*	32,115	50.4948%	16,216	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	*0*	*7.2351% (c)*	0	50.4948%	0	
21	*PLUS Trans. Related General Advertising Expense*	*0*	*7.2351% (c)*	0	50.4948%	0	
22	Total A&G [line 18 plus (19 thru 21)	*6,067,691*		*407,240*		*205,635*	
23	*Payroll Tax Expense*	*45,260*	*6.6703% (a)*	*3,019*	*50.4948%*	*1,524*	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	1,495	G/L Acct 926-05
FICA/Medicare	43,765	G/L Acct 926-06
MA Unemployment	0	
MA Universal Health	0	
Total	45,260	*To Line 23*

* Property Taxes			
	NBV Transmission Plant	3,206,035	Page 16, line 31g
	NBV General Plant	2,332,225	Page 17, line 30g less line 29g telecom
	Local property tax rate - 1st half	36.54	Page 3, line 9 of 2010 DPU State Return
	Local property tax rate - 2nd half	37.08	Page 3, line 9 of 2010 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

PTF Revenue Requirements
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	Mass DTE AR Reference for col (1)
	Depreciation Expense						
1	Transmission Depreciation	129,897		129,897	26.8039%	34,817	Page 16, line 31d
2	General Depreciation	319,302	6.6703% (a)	21,298	26.8039%	5,709	Page 17, line 30d less line 29 Telecom
3	Total (line 1+2)			151,195		40,526	
4	Amortization of Loss on Reacquired Debt	647,322	7.2351% (c)	46,834	26.8039%	12,553	Page 13, line 28d
5	Amortization of Investment Tax Credits	0	7.2351% (c)	0	26.8039%	0	None known
	Property Taxes *						
6	Transmission Property Taxes	118,014		118,014	26.8039%	31,632	See below
7	General Property Taxes	85,849	6.6703% (a)	5,726	26.8039%	1,535	
8	Total (line 6+7)			123,741		33,167	
	Transmission Operation and Maintenance	PER INTERPRETATIVE GUIDANCE DOCUMENT SECTION II.G RULES FOR HGED					
9	Operation and Maintenance	3,249,661		3,249,661	26.8039%	871,036	Page 40, line 50b
10	Transmission of Electricity by Others - #565	2,632,987		2,632,987	26.8039%	705,743	Page 40, line 38b
11	Load Dispatching - #561	0		0	26.8039%	0	Page 40, line 34b
12	**Station Expenses & Rents - #562 / #567					0	Page 40, line 35b, 40b Only if includes Support
13	O&M less lines 10, 11 & 12	616,674		616,674	26.8039%	165,293	
	Transmission Administrative and General						
14	Administrative and General	6,139,073					Page 42, line 7b less line 5b, less pg 41 line 56b telecom
15	*less Property Insurance (#924)*	*443,881*					*Page 41, line 47b*
16	*less Regulatory Commission Expenses (#928)*	*0*					*Page 41, line 50b*
17	*less General Advertising Expense (#930.1)*	*71,382*					*G/L Acct 930-03 Public Goodwill less in Lieu of Discounts & Fiber Optic Cable*
18	Subtotal [line 14 minus (15 thru 17)	5,623,810	6.6703% (a)	375,125	26.8039%	100,548	
19	*PLUS Property Insurance alloc. using Plant Allocation*	*443,881*	*7.2351% (c)*	32,115	26.8039%	8,608	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	*0*	*7.2351% (c)*	0	26.8039%	0	
21	*PLUS Trans. Related General Advertising Expense*	*0*	*7.2351% (c)*	0	26.8039%	0	
22	Total A&G [line 18 plus (19 thru 21)	*6,067,691*		*407,240*		*109,156*	
23	*Payroll Tax Expense*	*45,260*	*6.6703% (a)*	*3,019*	26.8039%	*809*	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	1,495	926-05
FICA/Medicare	43,765	926-06
MA Unemployment	0	
MA Universal Health	0	
Total	45,260	*To Line 23*

* Property Taxes

NBV Transmission Plant	3,206,035	Page 16, line 31g
NBV General Plant	2,332,225	Page 17, line 30g
Local property tax rate - 1st half	36.54	Page 3, line 9 of 2009 DPU State Return
Local property tax rate - 2nd half	37.08	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.

Sheet: Worksheet 5

▨ Shading denotes an input

Line No.				Mass DTE AR Reference			
	PTF Transmission Plant Allocation Factor	**Holyoke**					
		Pre-1997	Post-1996		<1/1/04	>1/1/04	
1	PTF Transmission Investment	4,271,276	2,267,299	(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	7,046	2,260,253	pg 8a lines 31c+31d+31e+31f
2	Total Transmission Investment	8,458,844	8,458,844	Page 8A, line 31g			
3	Percent Allocation (Line 1/Line 2)	50.4948%	26.8039%				
	Transmission Wages and Salaries Allocation Factor						
4	Direct Transmission Wages and Salaries	488,765		Page 40, line 33b, 35b, 36b, 39b, 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)	488,765					
7	Total Wages and Salaries	8,119,888		Page 42, line 25 less telecom Wages			
8	Administrative and General Wages and Salaries	792,451		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)	7,327,437					
11	Percent Allocation (Line 6/Line 10)	6.6703%					
	Plant Allocation Factor						
12	Total Transmission Investment	8,458,844		Line 2			
13	*plus Transmission-Related General Plant* *(Line 2 of Wkst. 3)*	504,483		*Worksheet 3, Line 2*			
14	*= Revised Numerator* *(Line 12 + Line 13)*	8,963,327					
15	Total Plant in Service	123,887,010		Page 8B, line 31g less line 15g, less line 29g telecom			
16	Percent Allocation (Line 14 / Line 15)	7.2351%					

(Line #4) Breakdown of Transmission Expenses by FERC #	**Expenses (*)**	**Labor (*)**	**Total from MDTE AR**
560	17,779	312,113	329,893
562	4,209	96,970	101,179
563	-	-	-
566	-	19,927	19,927
570	34,590	14,800	49,390
571-00	24,908	44,813	69,722
571-01	46,422	142	46,564
Total		488,765	

(*) From General Ledger Trial Balance Report for December 31, 2010 Yr End

Sheet: Worksheet 6

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.

			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]		1,039
	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			2,949
	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**			7,706
	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]		18,670
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 394 line	332(g)		1,385
	115 kV Read - Washington V148 line			
NU	**345 kV 363, 369 and 394 Seabrook lines**			1,133
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		0
	345 kV Millstone-Manchester 310 line	330.1(n)		11,192
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
	Total =		0	44,074

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

Holyoke Gas & Electric Department - 2011 Forecasted Transmission Projects In-Service

Primary Equipment Owner	Other Equipment Owner(s)	Projected In-Service Month/Year	Project	October 2007 Status	April 2008 Status	Substation ROW	Transmission ROW	Estimated Costs	Estimated % PTF	Estimated PTF In-Service Costs
Holyoke Gas & Electric Department		Dec-11	17L Outdoor Switchgear battery & Charger	n/a	n/a	Not Required	Not Required	70000	50%	**$35,000**
Holyoke Gas & Electric Department		Dec-11	Substation Security Upgrades	n/a	n/a	Not Required	Not Required	25000	100%	**$25,000**
Holyoke Gas & Electric Department		Dec-11	Ingleside & Holyoke 79 Relay Replacement	n/a	n/a	Not Required	Not Required	2500	100%	**$2,500**

2010 Forecasted Transmission Plant Additions = $62,500

```
Account/Description                                              Debits            Credits            Balance
 Date      Transaction                     Reference
 Type Work Order  Job     Vendor
Projects/Grants

0030-30-930-930-03-1                          PUBLIC GOODWILL                                                  .00  *

 1/11/10 FULL PG AD W/GREEN BORDER          000000000019050          227.50
 IN                 ST PATRICK'S COMMITTEE HOLYOKE INC
 1/31/10 1-54-10 MISC PREPAID JAN 10        000000000019349        1,050.00
 JE
 1/31/10 FIBER OPTIC CABLE CONNECTION       000000000019183          108.34
 JE
 2/03/10 PETTY CASH REIMBURSED              000000000019187           20.80
 IN                 PETTY CASH
 2/04/10 HOLYOKE MFG EDUC INITIATIVE        000000000019187          650.00
 IN                 WORLD IS OUR CLASSROOM, INC
 2/18/10 IN LIEU OF DISCOUNTS               000000000019302       32,500.00
 IN                 CONKLIN OFFICE SERVICES INC
 2/24/10 7/2/10 SPONSORSHIP @ HCC           000000000019335       12,025.00
 IN                 GREATER HOLYOKE CHAMBER OF
 2/24/10 GRAND COLLEEN FLOAT 3/21 PARADE    000000000019335        4,875.00
 IN                 ST PATRICK'S COMMITTEE HOLYOKE INC
 2/24/10 OPPORTUNITY LEVEL SPONSORSHIP      000000000019335          650.00
 IN                 GREATER HOLYOKE YMCA
 2/28/10 FIBER OPTIC CABLE CONNECTION       000000000019513          108.34
 JE
 2/28/10 2-44-10 RECLASS EXP TO MISC PP     000000000019543                          12,025.00
 JE
 2/28/10 2-43-10 MISC PREPAID FEBRUARY      000000000019543        1,050.00
 JE
 3/04/10 4/1/10 SPONSORSHIP-NORTHAMPTON     000000000019408          162.50
 IN                 ENCHANTED CIRCLE THEATER
 3/04/10 FULL PG AD                         000000000019408          130.00
 IN                 HOLYOKE YOUTH BASEBALL LEAGUE
 3/04/10 MAJOR SPONSORSHIP 4/16/10          000000000019408          325.00
 IN                 WISTARIAHURST MUSEUM
 3/19/10 SILVER SPONSORSHIP-B THOMPSON      000000000019546          975.00
 IN                 BOYS & GIRLS CLUB OF GREATER
 3/19/10 SPONSORSHIP-SR CITIZEN HOLIDAY TOUR 000000000019546         975.00
 IN                 MISC VENDOR
 3/19/10 GOLD SPONSOR-SPRING RECEPTION      000000000019546          325.00
 IN                 LOOMIS COMMUNITIES THE
 3/31/10 FIBER OPTIC CABLE CONNECTION       000000000019791          108.34
 JE
 3/31/10 3-49-10 MISC PP EXPENSES MARCH     000000000019788        3,455.00
 JE
 4/12/10 M#387 2010 CONTRIBUTION-EDC        000000000019735        1,300.00
 IN                 ECONOMIC DEVELOPMENT COUNCIL OF WMA
10/28/10 SPONSORSHIP-BRAIN TUMOR            000000000021210          487.50
 IN                 LT DANNY BOYLE MEMORIAL RUN
 4/08/10 SPONSORSHIP-BENEFIT GALA -HOLY MALL 000000000019713         195.00
 IN                 FUTURE BEGINS HERE
 4/26/10 TEE SIGN EAST MTN CC               000000000019838          325.00
 IN                 BLESSED SACRAMENT PTG
```

```
Account/Description                                                    Debits              Credits              Balance
 Date     Transaction                      Reference
 Type Work Order  Job    Vendor
Projects/Grants

0030-30-930-930-03-1                                 PUBLIC GOODWILL                                                .00  *

 4/26/10 SPONSORSHIP-4 GOLF HOLES          000000000019838            130.00
 IN                      ERIC CLAYTON HOCKEY SCHOLARSHIP FD
 4/27/10 SPONSORSHIP-COLLEGE SHOWER DINNER 000000000019843            650.00
 IN                      GIRLS INC OF HOLYOKE
 4/27/10 SPONSORSHIP-TEE/GREEN SIGN        000000000019843             65.00
 IN                      JOHNNY YEE SCHOLARSHIP FUND
 4/27/10 GREEN FLAG SPONSORSHIP            000000000019843            325.00
 IN                      VALLEY HEALTH SYSTEMS, INC
 4/30/10 FIBER OPTIC CABLE CONNECTION      000000000019915                               108.34
 JE
 4/30/10 FIBER OPTIC CABLE CONNECTION      000000000019917            108.34
 JE
 4/30/10 FIBER OPTIC CABLE CONNECTION      000000000019918            108.34
 JE
 4/30/10 4-37-10 MONTH PP EXP APRIL        000000000020004          3,455.00
 JE
 5/03/10 PETTY CASH REIMBURSED             000000000019897            195.00
 IN                      PETTY CASH
 5/31/10 5-42-10 MISC PREPAID EXPENSES MAY 000000000020225          3,455.00
 JE
 5/31/10 FIBER OPTIC CABLE CONNECTION      000000000020241            108.34
 JE
 6/11/10 FUTURE BEGINS HERE 5/2 SPONSORSHIP 000000000020177           650.00
 IN                      HOLYOKE PUBLIC LIBRARY
 6/07/10 BRONZE SPONSORSHIP                000000000020145            650.00
 IN                      JOHN DINAPOLI GOLF TOURNAMENT
 6/11/10 GREENS SPONSORSHIP-OAK RIDGE      000000000020177            162.50
 IN                      JERICHO HOUSE
 6/11/10 SPONSORSHIP-HERITAGE ST PARK      000000000020177            130.00
 IN                      MISC VENDOR
 6/14/10 INFLATABLES                       000000000020188          1,381.25
 IN                      WALKING ON AIR INC
 6/21/10 TEE/GREEN SIGN SPONSORSHIP        000000000020247            195.00
 IN                      BRIGHTSIDE FOR FAMILIES & CHILDREN
 6/22/10 SPONSORSHIP-ONE TIME              000000000020264            162.50
 IN                      HOLYOKE PUBLIC SCHOOLS
 6/22/10 SPONSORSHIP-YOUTH SOCCER TEAM     000000000020264            162.50
 IN                      HOLYOKE YOUTH SOCCER LEAGUE
 6/23/10 TEAM SPONSORSHIP-WYCKOFF CC       000000000020271            247.00
 IN                      PROVIDENCE MINISTRIES FOR THE NEEDY
 6/23/10 SPONSORSHIP-SPFLD CC              000000000020271            650.00
 IN                      SISTERS OF ST JOSEPH
 6/23/10 SPONSORSHIP RECOGNITION CAMPAIGN  000000000020271             65.00
 IN                      WESTMASS ELDERCARE INC
 6/30/10 FIBER OPTIC CABLE CONNECTION      000000000020433            108.34
 JE
 6/30/10 6-44-10 MISC PP EXP JUNE          000000000020430          3,455.00
 JE
```

Account/Description Date	Transaction	Type	Work Order	Job	Vendor	Reference	Debits	Credits	Balance
0030-30-930-930-03-1	PUBLIC GOODWILL								.00 *
7/01/10	FIBER OPTIC CABLE CONNECTION	JE				000000000020572		108.34	
7/01/10	FIBER OPTIC CABLE CONNECTION	JE				000000000020575	108.34		
7/05/10	1008-2470-1	IN			FEDEX	000000000020677	11.18		
7/09/10	FIREWORKS @HCC	IN			MISC VENDOR	000000000020390	650.00		
7/26/10	FULL PG AD PROG BOOK	IN			FRIENDS OF HOLYOKE HIGH FOOTBALL	000000000020497	65.00		
7/26/10	FULL PG COVER AD	IN			HOLYOKE CIVIC SYMPHONY	000000000020497	162.50		
7/31/10	7-48-10 MONTH PP EXP JULY	JE				000000000020699	3,450.00		
7/31/10	FIBER OPTIC CABLE CONNECTION	JE				000000000020706	108.34		
8/10/10	SPONSORSHIP GOLF OUTING	IN			HCC FOUNDATION	000000000020605	780.00		
7/31/10	FIBER OPTIC CABLE CONNECTION	JE				000000000020785	108.34		
8/17/10	MISC RECEIVABLES	JE				000000000020655		76.30	
8/31/10	ECON DEV DISC-CAP&ENERGY ADD'T	IN			SISTERS OF ST JOSEPH	000000000020742	42,250.00		
8/31/10	SPONSORSHIP	IN			NUEVA ESPERANZA	000000000020742	325.00		
8/31/10	SPONSORSHIP-VHF EVENTS	IN			VOLLEYBALL HALL OF FAME	000000000020742	3,250.00		
8/31/10	8-50-10 MONTH PP EXP AUGUST	JE				000000000020917	585.00		
9/09/10	FULL PG AD-FANCY STEPS	IN			CHILDRENS MUSEUM OF HOLYOKE	000000000020827	130.00		
9/09/10	SPONSORSHIP-EVENT	IN			MISC VENDOR	000000000020827	162.50		
9/09/10	SPONSORSHIP-MTN PARK MEMORIES	IN			HOLYOKE MERRY-GO-ROUND	000000000020827	650.00		
9/09/10	FULL PG AD-TEC PROG BOOK	IN			THE THERAPEUTIC EQUESTRIAN CENTER	000000000020827	227.50		
9/20/10	SPONSORSHIP AD	IN			HOLYOKE FIREMEN'S AID ASSOCIATION	000000000020906	65.00		
9/21/10	SPONSORSHIP-WYCKOFF CC	IN			MISC VENDOR	000000000020912	325.00		
9/30/10	9-52-10 MISC PP EXPENSES SEPTEMBER	JE				000000000021139	585.00		
9/30/10	FIBER OPTIC CABLE CONNECTION	JE				000000000021164	108.34		
10/28/10	SUSTAINING SPONSORSHIP	IN			VOLLEYBALL HALL OF FAME	000000000021210	3,250.00		

Projects/Grants

```
Account/Description                                                      Debits              Credits             Balance
 Date     Transaction                     Reference
 Type Work Order  Job    Vendor
Projects/Grants

0030-30-930-930-03-1                                   PUBLIC GOODWILL                                                  .00   *

10/29/10 FULL PG AD- EVENT 10/18/0         000000000021219                                65.00
 VC                     GREEK ORTHODOX CHURCH OF THE
10/31/10 FIBER OPTIC CABLE CONNECTION      000000000021407        108.34
 JE
10/31/10 10-55-10 MISC PREPAID EXP         000000000021404        585.00
 JE
11/09/10 SPONSORSHIP-REFRESHMENTS          000000000021313        162.50
 IN                     BOYS & GIRLS CLUB OF GREATER
11/09/10 SPONSORSHIP-VALLEY CUP FIELD HOCKEY 000000000021313      325.00
 IN                     CITY OF HOLYOKE PARKS & RECREATION
11/09/10 SPONSORSHIP-BASEBALL TEAM         000000000021313        650.00
 IN                     HOLYOKE COMMUNITY COLLEGE
11/09/10 SPONSORSHIP-CISCO SMART & CONN    000000000021313        325.00
 IN                     HCC FOUNDATION
11/09/10 SPONSORSHIP                       000000000021313         65.00
 IN                     HOLYOKE LIONS CLUB C/O THOMAS TERRY
11/10/10 PETTY CASH REIMBURSED             000000000021322        105.69
 IN                     PETTY CASH
11/10/10 ENERGY CONF SPONSORSHIP           000000000021322        650.00
 IN                     UNIVERSITY OF MA-CLEAN ENERGY CONN
11/09/10 SPONSORSHIP-HEALTH OF IT          000000000021313        325.00
 IN                     MISC VENDOR
11/09/10 SPONSORSHIP OF A TRIVIA CARD      000000000021313        162.50
 IN                     WISTARIAHURST MUSEUM
11/15/10 WISTARIAHURST                     000000000021423        585.00
 IN                     NES RENTALS
11/16/10 CREDIT FOR LIFE ED PROG           000000000021355        162.50
 IN                     MISC VENDOR
11/17/10 PROGRAM BOOK FULL PAGE AD         000000000021366        227.50
 IN                     ST PATRICK'S COMMITTEE HOLYOKE INC
11/17/10 SPONSORSHIP KICK OFF              000000000021366        130.00
 IN                     THE SALVATION ARMY C/O N BOSWORTH
11/17/10 SPONSORSHIP                       000000000021366         97.50
 IN                     SOUTHAMPTON YOUTH ATHLETICS ASSOC
11/22/10 CORPORATE LEADER SPONSORSHIP      000000000021403      7,020.00
 IN                     GREATER HOLYOKE CHAMBER OF
11/22/10 FULL PAGE AD-PROGRAM BOOK         000000000021403         65.00
 IN                     HOLYOKE KNIGHTS HOCKEY
11/22/10 FULL PAGE AD-PROGRAM BOOK         000000000021403        650.00
 IN                     HOLYOKE YOUTH FOOTBALL
11/30/10 FIBER OPTIC CABLE CONNECTION      000000000021678        108.34
 JE
11/30/10 11-57-10 MISC PREPAID EXPENSES NOV  000000000021667      585.00
 JE
12/14/10 11/23-24                          000000000021710      1,531.50
 IN                     ELM ELECTRICAL INC
12/17/10 LIEU OF ECON DEV DISC             000000000021648     30,161.00
 IN                     HOLYOKE COMMUNITY COLLEGE
```

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Account/Description                                          Debits          Credits           Balance
 Date     Transaction                    Reference
 Type Work Order  Job    Vendor
Projects/Grants

0030-30-930-930-03-1                          PUBLIC GOODWILL                                        .00  *

12/21/10 11/29 WORL                     000000000021780        263.38
 IN                     ELM ELECTRICAL INC
12/31/10 FIBER OPTIC CABLE CONNECTION   000000000021769        108.34
 JE
12/31/10 12-100-10 MISC PP EXPENSE DEC  000000000021827        585.00
 JE
 1/10/11 PETTY CASH REIMBURSED          000000000021787        279.48
 IN                     PETTY CASH
                                                         ____________    ____________
                                                           182,028.04       12,382.98       169,645.06
** PUBLIC GOODWILL                              Totals                                      169,645.06  *

                         Fund ELECTRIC            Totals   182,028.04       12,382.98       169,645.06
```

PREPARED 5/17/11 , 10:56:28
PROGRAM MADG140
Holyoke Gas & Electric Department

General Ledger

Account/Description Date Transaction Type Work Order Job Vendor Projects/Grants	Reference	Debits	Credits	Balance
Fund				
ELECTRIC		182,028.04	12,382.98	169,645.06
	====================	====================	====================	====================
Final totals		182,028.04	12,382.98	169,645.06

Less in Lieu of Discounts & Fiber Optic Cable Connection (circled items) -106,211.08

$63,433.98

** END OF REPORT **

PREPARED 5/16/11 , 14:51:08
PROGRAM MADG125
Holyoke Gas & Electric Department

Trial Balance

Account	Description	Debit	Credit
0030-30-930-930-03-2	PUBLIC GOODWILL LABOR	7,948.23	.00
ELECTRIC		7,948.23	.00
All Fund Totals		7,948.23	.00

PREPARED 4/13/11 , 13:51:43
PROGRAM MADG125
Holyoke Gas & Electric Department

Trial Balance

Account	Description	Debit	Credit
0030-30-926-926-05-1	UNEMPLOYMENT BENEFIT CLAIMS	1,494.61	.00
0030-30-926-926-06-1	FICA MEDICARE TAX	43,765.04	.00
ELECTRIC		45,259.65	.00
All Fund Totals		45,259.65	.00

PREPARED 4/13/11 , 10:35:04
PROGRAM MADG125
Holyoke Gas & Electric Department

Trial Balance

Account	Description	Debit	Credit
0030-30-560-560-00-1	TRANS OPER SUPV & ENG EXPENSES	17,779.22	.00
0030-30-560-560-00-2	TRANS OPER SUPV & ENG LABOR	312,113.37	.00
0030-30-562-562-00-1	TRANSMISSION STATION EXPENSES	4,209.25	.00
0030-30-562-562-00-2	TRANSMISSION STATION LABOR	96,970.19	.00
ELECTRIC		431,072.03	.00
All Fund Totals		431,072.03	.00

PREPARED 4/13/11 , 10:35:56
PROGRAM MADG125
Holyoke Gas & Electric Department

Trial Balance

Account	Description	Debit	Credit
0030-30-566-566-00-2	MISC TRANSMISSION PAYROLL	19,926.93	.00
0030-30-570-570-00-1	MAINT TRANSMISSION PLANT EXPENSE	34,590.05	.00
0030-30-570-570-00-2	MAINT TRANSMISSION PLANT LABOR	14,800.05	.00
0030-30-571-571-00-1	MAINT OVERHEAD LINES EXPENSE	24,908.17	.00
0030-30-571-571-00-2	MAINT OVERHEAD LINES LABOR	44,812.85	.00
0030-30-571-571-01-1	TRANS/MAINT CLEARANCE EXPENSE	46,421.97	.00
0030-30-571-571-01-2	TRANS/MAINT CLEARANCE LABOR	141.71	.00
ELECTRIC		185,601.73	.00
All Fund Totals		185,601.73	.00

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):	**2010**
Customer:	**Hudson Light & Power Department**
Customer's NABs Number:	
Name of Participant responsible for customer's billing:	**Hudson**
DUNs number of Participant responsible for customer's billing:	**10-775-5126**

		Pre-97 Revenue Requirements		Post-97 Revenue Requirements	
Total of Attachment F - Sections A through I	=	3,450	(a)		(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)		0	(d)		(i)
Sub Total - Sum (A through I) - J + K + (L through O)		3,450	(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:	3,450	(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: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)	3,450	(l)=(k)+(b)+(g)-(h)

Shading denotes an input

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	**Hudson Light & Power Department**	Reference
1	Transmission Plant	(A)(1)(a)	24,239	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)		24,239	
5	Accumulated Depreciation	(A)(1)(d)	375	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)		23,864	
10	Prepayments	(A)(1)(h)	6	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	295	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	121	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		24,286	
II.	REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	1,943	Worksheet 2
15	Depreciation Expense	(B)	375	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)	147	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	15	*Worksheet 4, line 17 column 5*
20	Operation & Maintenance Expense	(G)	913	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	57	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)		3,450	To Revenue Requirements Summary Sheet

Hudson Light & Power Department

Annual Revenue Requirements
for costs in 2009

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 = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp) / PTF Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

= (0.0000 +(0 + 0) / 24,286) x 0)
(1 - 0)

= 0.0000000

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp) / PTF Inv. Base) + Federal Income Tax)* State Income Tax Rate
(1 - State Income Tax Rate)

= (0.0000 +(0 + 0) / 24,286) + 0.0000000)* 0
(1 - 0)

= 0.0000000

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

		(PTF)	
INVESTMENT BASE	$	24,286	From Worksheet 1
x Cost of Capital Rate		0.0800000	
= Investment Return and Income Taxes		1,943	To Worksheet 1

Hudson Light & Power Department

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)
	Transmission Plant						
1	Transmission Plant	52,750	Directly Assigned	52,750		24,239	Line 1, Worksheet 5
2	General Plant	0	0.8451% (a)	0	45.9509%	0	Page 8B, line 29g
3	Total (line 1+2)			52,750		24,239	
4	Transmission Plant Held for Future Use	0		0	45.9509%	0	None known
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	815		815	45.9509%	375	Page 8A, line 31g less Page 16, line 31g
6	General Plant Accum.Depreciation	0	0.8451% (a)	0	45.9509%	0	Page 8B, line 29g less Page 17, line 29g
7	Total (line 5+6)			815		375	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	0	1.7279% (c)	0	45.9509%	0	None known
9	Accumulated Deferred Taxes (190)	0	1.7279% (c)	0	45.9509%	0	None known
10	Total (line 8+9)			0		0	
11	Transmission loss on Reacquired Debt	0	1.7279% (c)	0	45.9509%	0	None known
	Other Regulatory Assets						
12	FAS 106	0	0.8451% (a)	0	45.9509%	0	None known
13	FAS 109	0	1.7279% (c)	0	45.9509%	0	None known
14	Other Regulatory Liabilities (254.DK)	0	1.7279% (c)	0	45.9509%	0	
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments	710	1.7279% (a)	12	45.9509%	6	Page 10, line 26c
17	Transmission Materials and Supplies	37,128	1.7279% (a)	642	45.9509%	295	Page 14, line 16b

Per Guidance Document I. R. Section II.A.1 as well as Application of I. R. to MTO's

Line No.		(5) PTF Allocated	FERC Form 1 Reference for col (1)
18	Cash Working Capital		
19	Operation & Maintenance Expense	913	Worksheet 1, Line 20
20	Administrative & General Expense	57	Worksheet 1, Line 21
21	Transmission Support Expense	0	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)	970	
23		0.125	x 45 / 360
24	Total (line 22 * line 23)	121	

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

Hudson Light & Power Department

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	Mass DTE AR Reference for col (1)
	Depreciation Expense						
1	Transmission Depreciation	815		815	45.9509%	375	Page 16, line 31d
2	General Depreciation	0	0.8451% (a)	0	45.9509%	0	Page 17, line 29d
3	Total (line 1+2)			815		375	
4	Amortization of Loss on Reacquired Debt	0	1.7279% (c)	0	45.9509%	0	Page 12, line 28b
5	Amortization of Investment Tax Credits	0	1.7279% (c)	0	45.9509%	0	None known
	Property Taxes *						
6	Transmission Property Taxes	0		0	45.9509%	0	See below
7	General Property Taxes	18,534	1.7279% (c)	320	45.9509%	147	See below
8	Total (line 6+7)			320		147	
	Transmission Operation and Maintenance	**PER INTERPRETATIVE GUIDANCE DOCUMENT SECTION II.G RULES FOR HGED**					
9	Operation and Maintenance	1,988	B-2	1,988	0.459509	913	Page 40, line 50b
10	Transmission of Electricity by Others - #565	0		0	0.459509	0	Page 40, line 38b
11	Load Dispatching - #561	0		0	0.459509	0	Page 40, line 34b
12	**Station Expenses & Rents - #562 / #567					0	Page 40, line 35b, 40b
13	O&M less lines 10, 11 & 12	1,988		1,988	45.9509%	913	
	Transmission Administrative and General						
14	Administrative and General	14,829	From 12/31/10 Seabrook Op Exp Summary - MMWEC Share				Page 42, line 6b
15	*less Property Insurance (#924)*	*0*					*Page 41, line 47b*
16	*less Regulatory Commission Expenses (#928)*	*0*					*Page 41, line 50b*
17	*less General Advertising Expense (#930.1)*	*0*					*G/L Acct 913-01 Advertising - Goodwill*
18	Subtotal [line 14 minus (15 thru 17)]	14,829	0.8451% *(a)*	125	45.9509%	57	
19	***PLUS** Property Insurance alloc. using Plant Allocation*	*0*	*1.7279% (c)*	0	45.9509%	0	
20	***PLUS** Regulatory Comm. Exp. (FERC Assessments)*	*0*	*1.7279% (c)*	0	45.9509%	0	
21	***PLUS** Trans. Related General Advertising Expense*	*0*	*1.7279% (c)*	0	45.9509%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*14,829*		*125*		*57*	
23	*Payroll Tax Expense*	*3,837*	*0.8451% (a)*	*32*	*45.9509%*	*15*	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	3,837	408.1 From 12/31/10 Seabrook Op Exp Summary - MMWEC Share
FICA/Medicare	0	926-06
MA Unemployment	0	
MA Universal Health	0	
Total	3,837	*To Line 23*

* Property Taxes

		Transmission	General		
a	Gross Plant	52,750	-	Worksheet 3, lines 1 & 2	
b	Depr Reserve	815	0	Worksheet 3, lines 5 & 6	
c = a - b	Net Book Value	51,935	0		
	Property Tax Rate: Jan 00 - Jun 00	0.00	0.00	Page 3, line 9	rates are per $1,000 of assessment
	Property Tax Rate: Jul 00 - Dec 00	0.00	0.00	Page 3, line 9	
	Local Property Tax Based on NBV	$ -	$ -	THIS IS CAP LEVEL MENTIONED IN GUIDANCE DOCUMENT	
d	Total Net Plant	0	0	Page 17, line 34b	
e1	PILOT	0	0	Page 21, line 23	65% is associated with electric plant
e2	Public Goodwill (930-03)	-	0	General Ledger Trial Balance	
e3	Energy Management Services (930-04)	-	0	General Ledger Trial Balance	
e4	ECS/Energy Edge Plus (930-05)	-	0	General Ledger Trial Balance	
e5	Cadet Engineer Program (930-07-1)	-	0	General Ledger Trial Balance	
e5	Municipal Payment Discounts	-	0		
e5	Discounted Street Lighting (all electric)	-	0		
e5	Economic Development Discounts (65% e)	-	0		
e5	New Homeowner Discounts (65% elec)	-	0		
e5	Assistance Programs (30-171-02)	-	0	General Ledger Trial Balance	
e5	Below Market Service Labor (65% elec)	-	0		
f = c/d * (e1+e2+e3+e4+e5)		#DIV/0!	#DIV/0!	TAKE CAP LEVEL, SINCE ACTUAL IS HIGHER	

** 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.				Mass DTE AR Reference
	PTF Transmission Plant Allocation Factor	on Light & Power Department		
1	PTF Transmission Investment	24,239		5-Break Project Unitization Costs Sheet - Rec'd from H. Person (Cal
2	Total Transmission Investment	52,750		5-Break Project Unitization Costs Sheet - Rec'd from H. Person (Cal
3	Percent Allocation (Line 1/Line 2)	45.9509%		
	Transmission Wages and Salaries Allocation Factor			
4	Direct Transmission Wages and Salaries	49	B-1	From 570 Labor Report per C. Blaine @ Seabrook
5	Affiliated Company Transmission Wages and Salaries	0		
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	49		
7	Total Wages and Salaries	5,774	C-1	From Labor Report per C. Blaine @ Seabrook
8	Administrative and General Wages and Salaries			
9	Affiliated Company Wages and Salaries less A&G	0		
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	5,774		
11	Percent Allocation (Line 6/Line 10)	0.8451%		
	Plant Allocation Factor			
12	Total Transmission Investment	52,750		Per Above
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	0		
14	*= Revised Numerator (Line 12 + Line 13)*	52,750		
15	Total Plant in Service	**3,052,819**		Per MMWEC Accounting Records, less Accum Depreciation
16	Percent Allocation (Line 14 / Line 15)	1.7279%		

0.118
0.0774%

Sheet: Worksheet 6

Affiliated Company Wages and Salaries

🟨 Shading denotes an input

Line		**Hudson Light & Power Departme**
"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)	TOTAL 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 12/31/10

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

🟨 Shading denotes an input

Submitted on: May 23, 2010

Revenue Requirements for (year): Calendar Year 2010

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

		Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	=	1,668,196	(a)	353,308	(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 P)		(3,247,921)	(d)	(687,879)	(i)
Sub Total - Sum (A through I) - J + K + (L through P)		(1,579,725)	(e)=(a)-(b)+(c)+(d)	(334,571)	(j)
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:				(1,914,296)	(k) = (e) + (j)

MAINE ELECTRIC POWER COMPANY
RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/10

▨ Shading denotes an input

Line No.		Attachment F Reference	TOTAL	POST 96	PRE-97	Reference
				MEPCO		
	I. INVESTMENT BASE	*Section:*				
1	Transmission Plant	(A)(1)(a)	25,519,178	4,460,109	21,059,069	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	1,228,846	214,771	1,014,075	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)		26,748,024	4,674,880	22,073,144	
5	Accumulated Depreciation	(A)(1)(d)	24,450,901	4,273,401	20,177,500	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	399,675	69,853	329,822	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)	601,671	105,157	496,514	Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5+6+7+8)		2,095,127	576,489	2,721,980	
10	Prepayments	(A)(1)(h)	380,615	66,522	314,093	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)	120,255	21,017	99,237	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		2,595,997	664,028	3,135,310	
	II. REVENUE REQUIREMENTS					
14	Investment Return and Income Taxes	(A)	510,468	89,217	421,251	Worksheet 2
15	Depreciation Expense	(B)	227,376	39,740	187,636	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)	321,623	56,212	265,411	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	-	-	-	*Worksheet 4, line 17 column 5*
20	Operation & Maintenance Expense	(G)	642,709	112,329	530,380	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	319,328	55,810	263,518	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)	(2,634,097)	(460,374)	(2,173,723)	
28	Transmission Rents Received from Electric Property	(O)	(265,316)	(46,371)	(218,945)	FF I p.300.19.b
28	MGTSA Revenue	(P)	(1,036,387)	(181,134)	(855,253)	
29	Total Revenue Requirements (Line 14 thru 28)		(1,914,296)	(334,571)	(1,579,725)	

MAINE ELECTRIC POWER COMPANY
RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/10

▨ Shading denotes an input

		CAPITALIZATION 12/31/2010	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		8,306,786	100.00%	11.64%	11.64%	11.64%
TOTAL INVESTMENT RETURN	$	8,306,786	100.00%		11.64%	11.64%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.1164

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

= (0.1164 +(- + -) / 2,595,997) x 35%)
(1 - 0.35)

= 0.0626769

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)* State Income Tax Rate
(1 - State Income Tax Rate)

= (0.1164 +(- + -) / 2,595,997) + 0.0626769)* 8.93%
(1 - 0.0893)

= 0.0175596

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

		(PTF)	
INVESTMENT BASE	$	2,595,997	From Worksheet 1
x Cost of Capital Rate		0.1966365	
= Investment Return and Income Taxes		510,468	To Worksheet 1

MAINE ELECTRIC POWER COMPANY
RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/10

▨ 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)
	Transmission Plant						
1	Transmission Plant	25,519,178		25,519,178		25,519,178	207.58.g
2	General Plant	1,228,846	100.0000% (a)	1,228,846	100.0000%	1,228,846	207.99.g
3	Total (line 1+2)			26,748,024		26,748,024	
4	Transmission Plant Held for Future Use	-		-	100.0000%	-	
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	23,221,625		23,221,625	100.0000%	23,221,625	219.25.b
6	General Plant Accum.Depreciation	1,229,276	100.0000% (a)	1,229,276	100.0000%	1,229,276	219.28.b
7	Total (line 5+6)			24,450,901		24,450,901	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	(196,273)	99.8758% (c)	(196,029)	100.0000%	(196,029)	275.9.k
9	Accumulated Deferred Taxes (190)	596,445	99.8758% (c)	595,704	100.0000%	595,704	
10	Total (line 8+9)			399,675		399,675	
11	Transmission loss on Reacquired Debt	-	99.8758% (c)	-	100.0000%	-	
	Other Regulatory Assets/(Liabilities)						
12	FAS 106	-	100.0000% (a)	-	100.0000%	-	
13	FAS 109	(602,419)	99.8758% (c)	(601,671)	100.0000%	(601,671)	278.1.f
14	Other Regulatory Liabilities (254.DK)	-	99.8758% (c)	-	100.0000%	-	
15	Total (line 12+13+14)	(602,419)		(601,671)		(601,671)	
16	Transmission Prepayments	380,615	100.0000% (a)	380,615	100.0000%	380,615	111.57.c
17	Transmission Materials and Supplies	-	99.8758%	-	100.0000%	-	
18	Cash Working Capital						
19	Operation & Maintenance Expense					642,709	Worksheet 1, Line 20
20	Administrative & General Expense					319,328	Worksheet 1, Line 21
21	Transmission Support Expense					-	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					962,037	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					120,255	

(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 12/31/10

🟨 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)
	Depreciation Expense						
1	Transmission Depreciation	218,179		218,179	100.0000%	218,179	336.7.f
2	General Depreciation	9,197	100.0000% (a)	9,197	100.0000%	9,197	336.9.f
3	Total (line 1+2)			227,376		227,376	
4	Amortization of Loss on Reacquired Debt	-	99.8758% (c)	-	100.0000%	-	
5	Amortization of Investment Tax Credits	-	99.8758% (c)	-	100.0000%	-	
	Property Taxes *						
6	Transmission Property Taxes	322,023	0.998758	321,623	100.0000%	321,623	263.5i-9i
7	General Property Taxes	-	100.0000% (a)	-	100.0000%	-	
8	Total (line 6+7)			321,623		321,623	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	835,680		835,680	100.0000%	835,680	321.112.b
10	Transmission of Electricity by Others - #565	-		-	100.0000%	-	
11	Load Dispatching - #561	192,971		192,971	100.0000%	192,971	321.86b-87b
12	**Station Expenses & Rents - #562 / #567			-	100.0000%	-	
13	O&M less lines 10, 11 & 12	642,709		642,709	100.0000%	642,709	
	Transmission Administrative and General						
14	Administrative and General	319,611					323.194.b
15	*less Property Insurance (#924)*	*10,781*					323.185.b
16	*less Regulatory Commission Expenses (#928)*	*217,047*					323.189.b
17	*less General Advertising Expense (#930.1)*	*-*					
18	Subtotal [line 14 minus (15 thru 17)]	91,783	100.0000% (a)	91,783	100.0000%	91,783	
19	*PLUS Property Insurance alloc. using Plant Allocation*	*10,781*	*99.8758% (c)*	10,768	100.0000%	10,768	323.185.b
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	*217,047*	*99.8758% (c)*	216,777	100.0000%	216,777	323.189.b
21	*PLUS Trans. Related General Advertising Expense*	-	*99.8758% (c)*	-	100.0000%	-	
22	Total A&G [line 18 plus (19 thru 21)]	*319,611*		*319,328*		*319,328*	
23	*Payroll Tax Expense*	-	*100.0000% (a)*	-	*100.0000%*	-	

MAINE ELECTRIC POWER COMPANY
RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/10

▨ Shading denotes an input

Line No.			Reference
	PTF Transmission Plant Allocation Factor	**MEPCO**	
1	PTF Transmission Investment	25,519,178	207.58.g
2	Total Transmission Investment	25,519,178	207.58.g
3	Percent Allocation (Line 1/Line 2)	100.0000%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	1	
5	Affiliated Company Transmission Wages and Salaries	0	
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	1	
7	Total Wages and Salaries	1	
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)	1	
11	Percent Allocation (Line 6/Line 10)	100.0000%	
	Plant Allocation Factor		
12	Total Transmission Investment	25,519,178	Line 2
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	1,228,846	*Worksheet 3, Line 2*
14	*= Revised Numerator (Line 12 + Line 13)*	26,748,024	
15	Total Plant in Service	26,781,294	207.104.g
16	Percent Allocation (Line 14 / Line 15)	99.8758%	

MAINE ELECTRIC POWER COMPANY
RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/10

Affiliated Company Wages and Salaries

🟨 Shading denotes an input

Line		MEPCO
"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 12/31/10

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.

			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]		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 12/31/10

MEPCO Transmission Investment by Vintage 12/31/10

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	**$ 21,059,069**	**PRE97**
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	-		
2006	-		
2007	262,838.89		
2008	312,465.30		
2009	136,311.57		
2010	74,343.41	**$ 4,460,109**	**Post96**
Grand Total	25,519,177.49	**$ 25,519,178**	**TOTAL**

Completed by: Rachel Thurlow 05/17/2011

Municipal Support of the New England PTF for 2010

Municipal Support of the New England PTF for 2010

	HQ II AC Nstar (BECo)	HQ II AC NEP	HQ II Chester SVC NEH	Seabrook Tewksbury NEP	Seabrook Scobie & Newington NU	Millstone 3 NU	Wyman 4 CMP	Municipal Support Total	MMWEC's Seabrook Revenue Requirements	Support and Revenue Requirements Total
Braintree	$ 1,211	$ 21,758	$ 8,980	$ 2,743	$ 2,244	$ -	$ -	$36,936	$27,352	$64,288
Reading	$1,825	$32,789	$13,533	$2,841	$2,324	$14,162	$0	$67,475	$28,329	$95,804
Hingham	$472	$8,478	$3,499	$2,119	$1,734	$3,529	$0	**$19,832**	$21,136	**$40,967**
Hull	$141	$2,525	$1,042	$738	$603	$1,333	$541	**$6,923**	$7,356	**$14,280**
Middleborough	$418	$7,514	$3,101	$2,252	$1,842	$3,954	$714	**$19,796**	$22,454	**$42,250**
Pascoag,RI	$90	$1,617	$667	$478	$391	$0	$0	**$3,243**	$4,766	**$8,009**
Concord	$471	$8,458	$3,491	$0	$0	$0	$0	**$12,419**	$0	**$12,419**
Ashburnham	$70	$1,256	$518	$291	$238	$1,075	$0	**$3,449**	$2,905	**$6,354**
Boylston	$79	$1,415	$584	$380	$310	$925	$224	**$3,917**	$3,785	**$7,702**
Danvers	$940	$16,880	$6,967	$4,975	$4,070	$9,205	$0	**$43,037**	$49,612	**$92,649**
Georgetown	$91	$1,630	$673	$428	$350	$729	$0	**$3,901**	$4,266	**$8,167**
Groton,MA	$104	$1,866	$770	$576	$471	$891	$0	**$4,678**	$5,743	**$10,422**
Holden	$289	$5,197	$2,145	$1,776	$1,453	$2,544	$0	**$13,403**	$17,707	**$31,110**
Hudson	$579	$10,407	$4,295	$10,083	$6,127	$3,701	$1,455	**$36,648**	$71,232	**$107,880**
Ipswich	$0	$0	$0	$476	$390	$2,130	$0	**$2,996**	$4,751	**$7,747**
Littleton,MA	$288	$5,183	$2,139	$489	$400	$1,878	$714	**$11,092**	$4,875	**$15,966**
Mansfield	$657	$11,802	$4,871	$3,534	$2,891	$5,541	$0	**$29,295**	$35,240	**$64,535**
Marblehead	$333	$5,988	$2,471	$604	$494	$5,412	$1,197	**$16,499**	$6,022	**$22,521**
Middleton	$183	$3,296	$1,360	$1,467	$1,200	$1,541	$433	**$9,482**	$14,632	**$24,113**
N. Attleboro	$426	$7,660	$3,161	$1,691	$1,383	$6,112	$714	**$21,147**	$16,858	**$38,005**
Paxton	$69	$1,235	$510	$361	$296	$1,143	$0	**$3,613**	$3,603	**$7,216**
Peabody	$1,113	$19,996	$8,253	$5,054	$4,135	$10,405	$0	**$48,956**	$50,403	**$99,359**
Rowley	$62	$1,110	$458	$0	$0	$0	$0	**$1,630**	$0	**$1,630**
Shrewsbury	$633	$11,378	$4,696	$2,574	$2,106	$8,142	$1,786	**$31,317**	$25,673	**$56,989**
Sterling	$0	$0	$0	$914	$748	$1,030	$0	**$2,691**	$9,113	**$11,805**
Templeton	$214	$3,851	$1,589	$862	$705	$2,452	$0	**$9,673**	$8,594	**$18,267**
Wakefield	$489	$8,784	$3,625	$1,731	$1,416	$7,203	$1,885	**$25,132**	$17,261	**$42,394**
W.Boylston	$200	$3,594	$1,483	$811	$664	$2,775	$0	**$9,527**	$8,090	**$17,616**
Chicopee	$1,236	$22,202	$9,163	$0	$0	$0	$0	**$32,601**	$0	**$32,601**
S.Hadley	$454	$8,159	$3,368	$1,526	$1,248	$20,170	$0	**$34,925**	$15,218	**$50,143**
Westfield	$992	$17,831	$7,359	$1,630	$1,334	$39,009	$3,109	**$71,265**	$16,257	**$87,522**
Total Support:	**$11,094**	**$199,311**	**$82,261**	**$47,820**	**$36,998**	**$142,832**	**$12,772**	**$533,087**	$447,550	**$980,636**

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): **2010**

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**

		Pre-97 Revenue Requirements		Post-97 Revenue Requirements	
Total of Attachment F - Sections A through I	=	517,040	(a)		(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)		0	(d)		(i)
Sub Total - Sum (A through I) - J + K + (L through O)		517,040	(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:	517,040	(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: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)	517,040	(l)=(k)+(b)+(g)-(h)

▨ Shading denotes an input

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	▨	Reference
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)	56,108	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)		3,574,548	
10	Prepayments	(A)(1)(h)	3,249	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	44,155	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	18,181	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		3,640,133	
II.	REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	291,211	Worksheet 2
15	Depreciation Expense	(B)	56,108	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)	22,042	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	2,232	*Worksheet 4, line 17 column 5*
20	Operation & Maintenance Expense	(G)	136,822	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	8,625	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 * PTFPA
29	Total Revenue Requirements (Line 14 thru 28)		517,040	To Revenue Requirements Summary Shee

Massachusetts Municipal Wholesale Electric Company

Annual Revenue Requirements
for costs in 2009

▨ 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**

				PTF Inv.		Eq. AFUDC				
(b) Federal Income Tax	=	(R.O.E. +	(	(Tax Credit	+	of Deprec. Exp) /	PTF Inv. Base)	x	Federal Income Tax Rate	)
		(1						-	Federal Income Tax Rate	)
	=	(0.0000	+(	0	+	0) /	3,640,133)	x	0	)
		(1						-	0	)
	=	0.0000000								

				PTF Inv.		Eq. AFUDC					
(c) State Income Tax	=	(R.O.E. +	(	(Tax Credit	+	of Deprec. Exp) /	PTF Inv. Base)	+	Federal Income Tax	)*	State Income Tax Rate
		(1						-	State Income Tax Rate	)	
	=	(0.0000	+(	0	+	0) /	3,640,133)	+	0.0000000	)*	0
		(1						-	0	)	
	=	0.0000000									

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

		(PTF)	
INVESTMENT BASE	$	3,640,133	From Worksheet 1
x Cost of Capital Rate		0.0800000	
= Investment Return and Income Taxes		291,211	To Worksheet 1

Massachusetts Municipal Wholesale Electric Company

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)
	Transmission Plant						
1	Transmission Plant	7,901,166	Directly Assigned	7,901,166		3,630,656	Line 1, Worksheet 5
2	General Plant	0	0.8451% (a)	0	45.9509%	0	Page 8B, line 29g
3	Total (line 1+2)			7,901,166		3,630,656	
4	Transmission Plant Held for Future Use	0		0	45.9509%	0	None known
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	122,104		122,104	45.9509%	56,108	Page 8A, line 31g less Page 16, line 31g
6	General Plant Accum.Depreciation	0	0.8451% (a)	0	45.9509%	0	Page 8B, line 29g less Page 17, line 29g
7	Total (line 5+6)			122,104		56,108	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	0	1.7279% (c)	0	45.9509%	0	None known
9	Accumulated Deferred Taxes (190)	0	1.7279% (c)	0	45.9509%	0	None known
10	Total (line 8+9)			0		0	
11	Transmission loss on Reacquired Debt	0	1.7279% (c)	0	45.9509%	0	None known
	Other Regulatory Assets						
12	FAS 106	0	0.8451% (a)	0	45.9509%	0	None known
13	FAS 109	0	1.7279% (c)	0	45.9509%	0	None known
14	Other Regulatory Liabilities (254.DK)	0	1.7279% (c)	0	45.9509%	0	
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments	409,213	1.7279% (a)	7,071	45.9509%	3,249	Page 10, line 26c
17	Transmission Materials and Supplies	5,561,223	1.7279% (a)	96,092	45.9509%	44,155	Page 14, line 16b
			Per Guidance Document I. R. Section II.A.1 as well as Application of I. R. to MTO's				
18	Cash Working Capital						
19	Operation & Maintenance Expense					136,822	Worksheet 1, Line 20
20	Administrative & General Expense					8,625	Worksheet 1, Line 21
21	Transmission Support Expense					0	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					145,447	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					18,181	

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

Massachusetts Municipal Wholesale Electric Company

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	Mass DTE AR Reference for col (1)
	Depreciation Expense						
1	Transmission Depreciation	122,104		122,104	45.9509%	56,108	Page 16, line 31d
2	General Depreciation	0	0.8451% (a)	0	45.9509%	0	Page 17, line 29d
3	Total (line 1+2)			122,104		56,108	
4	Amortization of Loss on Reacquired Debt	0	1.7279% (c)	0	45.9509%	0	Page 12, line 28b
5	Amortization of Investment Tax Credits	0	1.7279% (c)	0	45.9509%	0	None known
	Property Taxes *						
6	Transmission Property Taxes	0		0	45.9509%	0	See below
7	General Property Taxes	2,776,168	1.7279% (c)	47,969	45.9509%	22,042	See below
8	Total (line 6+7)			47,969		22,042	
	Transmission Operation and Maintenance	PER INTERPRETATIVE GUIDANCE DOCUMENT SECTION II.G RULES FOR HGED					
9	Operation and Maintenance	297,757	B-2	297,757	0.459509	136,822	Page 40, line 50b
10	Transmission of Electricity by Others - #565	0		0	0.459509	0	Page 40, line 38b
11	Load Dispatching - #561	0		0	0.459509	0	Page 40, line 34b
12	**Station Expenses & Rents - #562 / #567					0	Page 40, line 35b, 40b
13	O&M less lines 10, 11 & 12	297,757		297,757	45.9509%	136,822	
	Transmission Administrative and General						
14	Administrative and General	2,221,158	From 12/31/10 Seabrook Op Exp Summary - MMWEC Share				Page 42, line 6b
15	*less Property Insurance (#924)*	*0*					*Page 41, line 47b*
16	*less Regulatory Commission Expenses (#928)*	*0*					*Page 41, line 50b*
17	*less General Advertising Expense (#930.1)*	*0*					*G/L Acct 913-01 Advertising - Goodwill*
18	Subtotal [line 14 minus (15 thru 17)]	2,221,158	0.8451% *(a)*	18,771	45.9509%	8,625	
19	***PLUS*** *Property Insurance alloc. using Plant Allocation*	*0*	*1.7279% (c)*	0	45.9509%	0	
20	***PLUS*** *Regulatory Comm. Exp. (FERC Assessments)*	*0*	*1.7279% (c)*	0	45.9509%	0	
21	***PLUS*** *Trans. Related General Advertising Expense*	*0*	*1.7279% (c)*	0	45.9509%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*2,221,158*		*18,771*		*8,625*	
23	*Payroll Tax Expense*	*574,723*	*0.8451% (a)*	*4,857*	*45.9509%*	*2,232*	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	574,723	408.1 From 12/31/10 Seabrook Op Exp Summary - MMWEC Share
FICA/Medicare	0	926-06
MA Unemployment	0	
MA Universal Health	0	
Total	574,723	*To Line 23*

* Property Taxes

		Transmission	General		
a	Gross Plant	7,901,166	-	Worksheet 3, lines 1 & 2	
b	Depr Reserve	122,104	0	Worksheet 3, lines 5 & 6	
c = a - b	Net Book Value	7,779,062	0		
	Property Tax Rate: Jan 00 - Jun 00	0.00	0.00	Page 3, line 9	rates are per $1,000 of assessment
	Property Tax Rate: Jul 00 - Dec 00	0.00	0.00	Page 3, line 9	
	Local Property Tax Based on NBV	$ -	$ -	THIS IS CAP LEVEL MENTIONED IN GUIDANCE DOCUMENT	
d	Total Net Plant	0	0	Page 17, line 34b	
e1	PILOT	0	0	Page 21, line 23	65% is associated with electric plant
e2	Public Goodwill (930-03)	-	0	General Ledger Trial Balance	
e3	Energy Management Services (930-04)	-	0	General Ledger Trial Balance	
e4	ECS/Energy Edge Plus (930-05)	-	0	General Ledger Trial Balance	
e5	Cadet Engineer Program (930-07-1)	-	0	General Ledger Trial Balance	
e5	Municipal Payment Discounts	-	0		
e5	Discounted Street Lighting (all electric)	-	0		
e5	Economic Development Discounts (65% e)	-	0		
e5	New Homeowner Discounts (65% elec)	-	0		
e5	Assistance Programs (30-171-02)	-	0	General Ledger Trial Balance	
e5	Below Market Service Labor (65% elec)	-	0		
f = c/d * (e1+e2+e3+e4+e5)		#DIV/0!	#DIV/0!	TAKE CAP LEVEL, SINCE ACTUAL IS HIGHER	

** 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.				Mass DTE AR Reference
	PTF Transmission Plant Allocation Factor	**0**		
1	PTF Transmission Investment	3,630,656		5-Break Project Unitization Costs Sheet - Rec'd from H. Person (Cal
2	Total Transmission Investment	7,901,166		5-Break Project Unitization Costs Sheet - Rec'd from H. Person (Cal
3	Percent Allocation (Line 1/Line 2)	45.9509%		
	Transmission Wages and Salaries Allocation Factor			
4	Direct Transmission Wages and Salaries	62,088	B-1	From 570 Labor Report per C. Blaine @ Seabrook
5	Affiliated Company Transmission Wages and Salaries	0		
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	62,088		
7	Total Wages and Salaries	7,346,752	C-1	From Labor Report per C. Blaine @ Seabrook
8	Administrative and General Wages and Salaries			
9	Affiliated Company Wages and Salaries less A&G	0		
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	7,346,752		
11	Percent Allocation (Line 6/Line 10)	0.8451%		
	Plant Allocation Factor			
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	**457,268,125**		Per MMWEC Accounting Records, less Accum Depreciation
16	Percent Allocation (Line 14 / Line 15)	1.7279%		

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		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.

			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]		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)

Sheet: Input Panel

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 2010

Rates Effective for the Period: June 2011
Through: May 2012

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:

	Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	$88,476,379	(a)	$117,066,192	(f)
Total of Attachment F - Section J - Support Revenue	$6,543,377	(b)	$0	(g)
Total of Attachment F - Section K - Support Expense	$881,501	(c)	$0	(h)
Total of Attachment F - Section (L through O)	($1,184,933)	(d)	($2,447,314)	(i)
Sub Total - Sum (A through I) - J + K + (L through O)	$81,629,570	(e)=(a)-(b)+(c)+(d)	$114,618,878	(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	N/A		$19,133,246	(k)
Annual True-up (per Attachment C to Attachment F Implementation Rule)	($1,355,645)	(l)	($16,392,129)	(m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)	$80,273,925	(n)=(e)+(l)	$117,359,995	(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)			$197,633,920	(p) = (n) + (o)

New England Power Company
Transmission Revenue Requirements of PTF Facilities
2010 True-up

I. ANNUAL TRUE-UP PER ROE COMPLIANCE WITH FERC ROE ORDER

		PRE 97	POST 1996
1	**Transmission Revenue Requirements (as billed)**	$82,941,498	$130,482,383
2	True-up 2010 Actual Annual RR	$81,629,570	$114,618,878
3	(Over)/Under (Line 2 - Line 1)	(1,311,927)	(15,863,504)
4	Per Month (Line 3/12)	(109,327)	(1,321,959)
5	Total Rate Year (Over)/Under	$ (1,311,927)	$ (15,863,504)

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

	Undercollection/(Overcollection)
Pre 97	($1,311,927)
Post 96	($15,863,504)

Initial Billing Period	**PRE 97 Balance**	**POST 1996 Balance**	**FERC Monthly Interest Rate**	**PRE 97 Interest**	**POST 1996 Interest**
June 2010	$ (1,311,927)	$ (15,863,504)	0.27%	$ (3,542)	$ (42,831)
July 2010	(1,315,470)	(15,906,336)	0.28%	(3,683)	(44,538)
August 2010	(1,315,470)	(15,906,336)	0.28%	(3,683)	(44,538)
September 2010	(1,315,470)	(15,906,336)	0.27%	(3,552)	(42,947)
October 2010	(1,326,388)	(16,038,358)	0.28%	(3,714)	(44,907)
November 2010	(1,326,388)	(16,038,358)	0.27%	(3,581)	(43,304)
December 2010	(1,326,388)	(16,038,358)	0.28%	(3,714)	(44,907)
January 2011	(1,337,397)	(16,171,477)	0.28%	(3,745)	(45,280)
February 2011	(1,337,397)	(16,171,477)	0.25%	(3,343)	(40,429)
March 2011	(1,337,397)	(16,171,477)	0.28%	(3,745)	(45,280)
April 2011	(1,348,230)	(16,302,466)	0.27%	(3,640)	(44,017)
May 2011	(1,348,230)	(16,302,466)	0.28%	(3,775)	(45,647)
		Total Interest		**$ (43,718)**	**$ (528,625)**
		True-Up		(1,311,927)	$ (15,863,504)
		Total TU & Interest		**$ (1,355,645)**	**$ (16,392,129)**

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 2010

Rates Effective for the Period: June 2011
Through: May 2012

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:

	Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	$88,476,379	(a)	$117,066,192	(f)
Total of Attachment F - Section J - Support Revenue	$6,543,377	(b)	$0	(g)
Total of Attachment F - Section K - Support Expense	$881,501	(c)	$0	(h)
Total of Attachment F - Section (L through O)	($1,184,933)	(d)	($2,447,314)	(i)
Sub Total - Sum (A through I) - J + K + (L through O)	$81,629,570	(e)=(a)-(b)+(c)+(d)	$114,618,878	(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	N/A		$19,133,246	(k)
Annual True-up (per Attachment C to Attacment F Im[plementation Rule)	N/A	(l)	N/A	(m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)	$81,629,570	(n)=(e) + (l)	$133,752,124	(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:			$215,381,695	(p) = (n) + (o)

New England Power Company
Annual Revenue Requirements of PTF Facilities
For Costs in 2010

PRE-1997

Shading denotes an input

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	NEP	Reference
1	Transmission Plant	(A)(1)(a)	$338,266,265	Worksheet 3, line 1&2 column 5
2	General Plant	(A)(1)(b)	$1,627,889	Worksheet 3, line 3 column 5
3	Plant Held For Future Use	(A)(1)(c)	$243,276	Worksheet 3, line 5 column 5
4	Total Plant (Lines 1+2+3)		$340,137,430	
5	Accumulated Depreciation	(A)(1)(d)	($78,343,474)	Worksheet 3, line 8 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	($74,399,992)	Worksheet 3, line 11 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	$165,065	Worksheet 3, line 12 column 5
8	Other Regulatory Assets	(A)(1)(g)	$10,501,692	Worksheet 3, line 16 column 5
9	Net Investment (Line 4+5+6+7+8)		$198,060,721	
10	Prepayments	(A)(1)(h)	$0	Worksheet 3, line 17 column 5
11	Materials & Supplies	(A)(1)(i)	$1,057,292	Worksheet 3, line 18 column 5
12	Cash Working Capital	(A)(1)(j)	$1,871,195	Worksheet 3, line 25 column 5
13	Total Investment Base (Line 9+10+11+12)		$200,989,208	
	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	$25,517,771	Worksheet 2
15	Depreciation Expense	(B)	$7,715,306	Worksheet 4, line 3, column 5
16	Amortization of Loss on Reacquired Debt	(C)	$69,423	Worksheet 4, line 4, column 5
17	Investment Tax Credit	(D)	($93,765)	Worksheet 4, line 5, column 5
18	Property Tax Expense	(E)	$5,356,815	Worksheet 4, line 6, column 5
19	Payroll Tax Expense	(F)	$488,170	Worksheet 4, line 22, column 5
20	Operation & Maintenance Expense	(G)	$7,819,390	Worksheet 4, line 11, column 5
21	Administrative & General Expense	(H)	$7,150,169	Worksheet 4, line 21, column 5
22	Transmission Related Integrated Facilities Charge	(I)	$34,453,101	Attachment 4, line 6
23	Transmission Support Revenue	(J)	($6,543,377)	Worksheet 6
24	Transmission Support Expense	(K)	$881,501	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)	($918,817)	Attachment 7
28	Transmission Rents Received from Electric Property	(O)	($266,116)	Attachment 6
29	Total Revenue Requirements (Line 14 thru 28)		$81,629,570	

New England Power Company
Annual Revenue Requirements
For Costs in 2010

▨ Shading denotes an input

	CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$410,350,000	35.93%	1.25%	0.45%	
PREFERRED STOCK	$1,111,700	0.10%	6.02%	0.01%	0.01%
COMMON EQUITY	$730,712,039	63.98%	11.64%	7.45%	7.45%
TOTAL INVESTMENT RETURN	$1,142,173,739	100.01%		7.91%	7.46%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0791

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

= (0.0746 +(($93,765) + $231,369) / $200,989,208) x 0.35)
(1 - 0.35)

= 0.0405379

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)* State Income Tax Rate
(1 - State Income Tax Rate)

= (0.0746 +(($93,765) + $231,369) / $200,989,208) + 0.0405379)* 0.059466
(1 - 0.059466)

= 0.0073230

(a)+(b)+(c) Cost of Capital Rate = 0.1269609

	(PTF)	
INVESTMENT BASE	$200,989,208	From Worksheet 1
x Cost of Capital Rate	0.1269609	
= Investment Return and Income Taxes	$25,517,771	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					$351,352,992	Attachment 1, Page 1
2	Less: Plant Assoc. HVDC Leases					($13,086,728)	Attachment 2
3	General Plant	$6,894,870	99.7459% (a)	$6,877,350	23.6703% (b)	$1,627,889	FERC Form 1 Page 207.99g
4	Total (line 1+2+ 3)			$6,877,350		$339,894,154	
5	Transmission Plant Held for Future Use	$1,027,771		$1,027,771	23.6703% (b)	$243,276	FERC Form 1 Page 214.2,4,9
	Transmission Accumulated Depreciation						
6	Transmission Accumulated Depreciation	($325,966,071)		($325,966,071)	23.6703% (b)	($77,157,147)	FERC Form 1 Page 219.25
7	General Plant Accumulated Depreciation	($5,024,647)	99.7459% (a)	($5,011,879)	23.6703% (b)	($1,186,327)	FERC Form 1 Page 219.28
8	Total (line 6+ 7)			($330,977,950)		($78,343,474)	
	Transmission Accumulated Deferred Taxes						
9	Accumulated Deferred Taxes (281-283)	($374,482,727)	99.2566% (c)	($371,698,822)	23.6703% (b)	($87,982,226)	FERC Form 1 Page 113.62-64
10	Accumulated Deferred Taxes (190)	$57,810,678	99.2566% (c)	$57,380,913	23.6703% (b)	$13,582,234	FERC Form 1 Page 111.82
11	Total (line 9+ 10)			($314,317,909)		($74,399,992)	
12	Transmission Loss on Reacquired Debt	$697,351	100.0000%	$697,351	23.6703% (b)	$165,065	FERC Form 1 Page 111.81c
	Other Regulatory Assets						
13	FAS 106	$0	99.7459% (a)	$0	23.6703% (b)	$0	
14	FAS 109 (Asset Account 182.3)	$44,366,536	100.0000%	$44,366,536	23.6703% (b)	$10,501,692	FERC Form 1 Page 232.7f
15	FAS 109 (Liability Account 254)	$0	100.0000%	$0	23.6703% (b)	$0	FERC Form 1 Page 278
16	Total (line 13+14+ 15)	$44,366,536		$44,366,536		$10,501,692	
17	Transmission Prepayments	$0	99.7459% (a)	$0	23.6703% (b)	$0	FERC Form 1 Page 111.57c
18	Transmission Materials and Supplies	$4,466,745		$4,466,745	23.6703% (b)	$1,057,292	FERC Form 1 Page 227.8c
19	Cash Working Capital						
20	Operation & Maintenance Expense					$7,819,390	Worksheet 1, Line 20
21	Administrative & General Expense					$7,150,169	Worksheet 1, Line 21
22	Transmission Support Expense					$0	Worksheet 6
23	Subtotal (line 20+21+22)					$14,969,559	
24						0.1250	x 45 / 360
25	Total (line 23 * line 24)					$1,871,195	

(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)
	Depreciation Expense						
1	Transmission Depreciation	$32,237,934		$32,237,934	23.6703% (b)	$7,630,816	FERC Form 1 Page 336.7b
2	General Depreciation	$357,854	99.7459% (a)	$356,945	23.6703% (b)	$84,490	FERC Form 1 Page 336.10b
3				$32,594,879		$7,715,306	
4	Amortization of Loss on Reacquired Debt	$293,292	100.0000%	$293,292	23.6703% (b)	$69,423	FERC Form 1 Page 117.64c
5	Amortization of Investment Tax Credits	($396,129)	100.0000%	($396,129)	23.6703% (b)	($93,765)	FERC Form 1 Page 266.8f - Footnote (f)
6	Property Taxes	$22,630,955	100.0000%	$22,630,955	23.6703% (b)	$5,356,815	FERC Form 1 Page 263.10,17,23,28i - Footnote (e)
	Transmission Operation and Maintenance						
7	Operation and Maintenance	$60,951,521		$60,951,521	23.6703% (b)	$14,427,408	FERC Form 1 Page 321.112b
8	Transmission of Electricity by Others - #565	$16,215,370		$16,215,370	23.6703% (b)	$3,838,227	FERC Form 1 Page 321.96b
9	Load Dispatching - #561 (excl #561.3)	$11,701,546		$11,701,546	23.6703% (b)	$2,769,791	FERC Form 1 Page 321.84-92b less 87b
10	**Station Expenses & Rents - #562 / #567	$0				$0	FERC Form 1 Page 321.93b & .98b
11	O&M less lines 8, 9 & 10	$33,034,605		$33,034,605	23.6703% (b)	$7,819,390	
	Transmission Administrative and General						
12	Total Administrative and General	$32,504,326					FERC Form 1 Page 323.197b
13	Less: Property Insurance (#924)	($179,245)					FERC Form 1 Page 323.185b
14	Less: Regulatory Commission Expenses (#928)	$4,562,078					FERC Form 1 Page 323.189b
15	Less: General Advertising Expense (#930.1)	$0					FERC Form 1 Page 323.191b
16	Subtotal [line 12 minus (13 thru 15)]	$28,121,493	99.7459% (a)	$28,050,036	23.6703% (b)	$6,639,528	
17	Plus: Property Insurance Allocated using Plant Allocatior	($179,245)	99.2566% (c)	($177,912)	23.6703% (b)	($42,112)	Line 13
18	Plus: Regulatory Commission Expense	$2,349,311	99.2566% (c)	$2,331,846	23.6703% (b)	$551,955	Attachment 5 Line 6
19	Plus: Specifically identifed Trans. Related General Advertising Expense	$0		$0	23.6703% (b)	$0	Line 15
20	Plus: Specifically identifed Trans. Related Regulatory Expense	$3,370		$3,370	23.6703% (b)	$798	FERC Form 1 Page 350.18c
21	Total A&G [line 16 + (17 thru 20)]	$30,294,929		$30,207,340		$7,150,169	
22	Payroll Tax Expense	$2,067,627	99.7459% (a)	$2,062,373	23.6703% (b)	$488,170	FERC Form 1 Page 263.3,4i - Footnote (d)

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

Federal Unemployment	($37,667)
FICA	$2,105,294
Payroll Taxes	$0
State Unemployment	$0
Total	$2,067,627

(e) Property Taxes FF1, Page 263i

Massachusetts	$19,219,508
New Hampshire	$2,582,427
Vermont	$685,578
Maine	$0
Rhode Island	$143,442
Connecticut	$0
	$22,630,955

(a) Worksheet 5 Line 11
(b) Worksheet 5 Line 3
(c) Worksheet 5 Line 16
(d) Transmission Only - Payroll Taxes - Specifically identified in FERC From 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	$351,352,992	Attachment 1, Page 1
2		$1,484,361,243	FERC Form 1 Page 207.58g - Page 200.4b
3	Percent Allocation (Line 1/Line 2)	23.6703%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	$0	FERC Form 1 Page 354.14b
5	Affiliated Company Transmission Wages and Salaries	$22,444,501	General Ledger Query
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	$22,444,501	
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	$22,501,688	General Ledger Query
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	$22,501,688	
11	Percent Allocation (Line 6/Line 10)	99.7459%	
	Plant Allocation Factor		
12	Total Transmission Investment	$1,484,361,243	Line 2
13	plus Transmission-Related General Plant	$6,877,350	Worksheet 3, Line 3, Column 3
14	= Revised Numerator (Line 12 + Line 13)	$1,491,238,593	
15	Total Plant in Service	$1,502,407,856	FERC Form 1 Page 207.104g - Page 200.4b
16	Percent Allocation (Line 14 / Line 16)	99.2566%	

Shading denotes input

New England Power Company
Pre-97 RNs Revenue Requirments
For Test Year Ended 12/31/2010

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.

			TOTAL	
Participant	**PTF Supporting Facilities**	**FERC Form 1 Reference**	**Revenues**	**Expenses**
			(a)	**(b)**
NSTAR	115 kV Millbury-Medway 201 Line	Pg 332 Line 2 Col (g)		$4,633
	HQ Phase II - AC in MA	Pg 332 Line 5 Col (g)		$106,178
	345 kV "stabilizer" 342 Line	Pg 332 Line 3 Col (g)		$63,954
	345 kV Carver - Walpole 331 Line	Pg 332 Line 13 Col (g)		$12,079
	Second Canal Line	Pg 332 Line 4 Col (g)		$47,040
	Bell Rock Road	Page 330.5 Line 12	$37,353	
	Boston-Edison [345 kV Sandy-Tewksbury 337 line-345kV Tewksbury-Woburn 338 Line]	Page 330 Line 4	$72,849	
	Boston-Edison [115 kV Tewksbury - Woburn M139 line - 115kV Tewksbury-Woburn N140 Line]	Page 330 Line 3	$108,916	
	Boston Edison -345 kV Golden Hills-Mystic 349 Line	Page 330 Line 2	$477,334	
	Boston Edison -345 kV NH/MA border - Tewksbury 394 Line (Seabrook	Page 330.1 Line 8	$240,367 *	
EUA	345 kV Medway - Bridgewater 344 Line	Pg 330.5, Line 11	$193,987	
NU	Public Service Co. -Moore 115 kV Substation	Page 330.1 Line 5	$13,319	
NEP	Chester SVC	Transmission Billing		$647,617
	HQ Phase II - AC in MA	Page 330 Line 11	$5,358,445	
	MWRA Transmission (MDC)	Contract - Line Lease/Use		$0
VT Elec Co.	Comerford 115 kV Substation	Page 330.1 Line 12	$40,807	
		Totals	**$6,543,377**	**$881,501**

* Adjusted FERC Form Pg 330.1 Line 8 to reflect FERC Order #ER09-1764-000 amending the Seabrook Transmission Support Agreement

FF1 Pg 330.1 Line 8	$	(3,957,093)
Add Back: FP&L Write-Off	$	3,703,371
Add Back: Refunds to MMWEC,Taunton & Hudson	$	494,089
FF1 Adjusted for RNS	**$**	**240,367**

Amount by which Support Expense exceeds Support Revenues (To Worksheet 3, Line 22, Column 5)	$0

Attachment 1

🟨 Shading denotes an input

New England Power Company
2010 Informational Filing
PTF Plant Allocation

				Percent Pre/Post
1	2009	Pre-1997 PTF Transmission Plant	$350,766,082	
2	2009	Post-1996 PTF Transmission Plant	$640,156,098	
3	2010	Additions/Retirements	$86,100,929	
4	2010	Pre-1997 PTF Transmission Plant	$351,352,992	32.62%
5	2010	Post-1996 PTF Transmission Plant	$725,670,117	67.38%
6	2010	Total PTF Transmission Plant	$1,077,023,109	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

Attachment 2

🟨 Shading denotes an input

GROSS PLANT ASSOC. WITH HVDC LEASES
2010

LINE NO		(HVDC) NHH/NEH LEASE
1	Gross Plant Value Comerford Station to Tewksbury Line	$14,269,187
	Allocation	
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 Hydo 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.

▨ Shading denotes an input

Attachment 3

New England Power Company
Determination of Book Depreciation on Equity AFUDC

		2010
1	Total Current Year Book Depreciation on Equity AFUDC	$980,344
2	Less: Specifically Identified Transmission-Related	
	Tewksbury Line	$54,708
	Hydro-Quebec	$23,543
	MontaupTransmission 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
		$592,969
3	Total Unidentified Book Depreciation on Equity AFUDC	$387,375
4	Plant Allocator Factor	99.2566%
5	Allocated Transmission Related Book Depreciation on Equity AFUDC	$384,495
6	Plus: Specifically Identified Transmission-Related Equity AFUDC	$592,969
7	Total Transmission-Related Equity AFUDC	$977,464
8	Pre-97 PTF Allocation Factor	23.6703%
9	Transmission-Related Equity AFUDC	$231,369

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

Attachment 4

🟨 Shading denotes an input

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

		Narragansett **2010**	**MECO** **2010**
1	Total Integrated Facilities Charges	$43,062,545	$8,366,692
2	Total 2010 PTF Property	$206,391,771	$21,044,551
3	Total Transmission Plant in 2010	$290,660,448	$45,434,656
4	NECO or MECO PTF Plant Allocator	71.01%	46.32%
5	PTF Related Integrated Facilities Charge	$30,577,793	$3,875,308
6	**Total Integrated Facilities**		**$34,453,101**

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 2010 Regulatory Commission Expense

Line No.		2010	Source
1	Total Regulatory Commission Expense - NEP	$4,562,078	FERC Form1 Page 350.46d
2	Less: New Hampshire PUC Assessment	$57,482	FERC Form1 Page 350.2d
3	Less: Mass Emergency Fund	$0	FERC Form1 Page 350.7d
4	Less Mass DPU Special Assessment	$293,722	FERC Form1 Page 350.8d
5	Less: Utility Expenses	$1,861,563	FERC Form1 Page 350.46c
6	Total Federal Assessments	$2,349,311	Line 1 - (Line 2-5)

Attachment 6

Transmission Rents Received from Electric Property
New England Power Company

	2010
Revenues	$1,124,263
Plant Allocation Factor	100.00%
Transmission Allocated	$1,124,263
PTF Allocation	23.6703%
Total PTF Revenue	$266,116

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

Attachment 7

Revenue for Short-Term Transmission Service under the NEPOOL Tariff

New England Power Company

	2010
Revenues	$2,816,506
Pre-97 PTF Percent	32.6226%
Total Pre-97 PTF Revenue	$ 918,817

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

Sheet: Input Panel

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 2010

Rates Effective for the Period: June 2011
Through: May 2012

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:

	Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	$88,476,379	(a)	$117,066,192	(f)
Total of Attachment F - Section J - Support Revenue	$6,543,377	(b)	$0	(g)
Total of Attachment F - Section K - Support Expense	$881,501	(c)	$0	(h)
Total of Attachment F - Section (L through O)	($1,184,933)	(d)	($2,447,314)	(i)
Sub Total - Sum (A through I) - J + K + (L through O)	$81,629,570	(e)=(a)-(b)+(c)+(d)	$114,618,878	(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	N/A		$19,133,246	(k)
Annual True-up (per Attachment C to Attachment F Implementation Rule)	N/A	(l)	N/A	(m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)	$81,629,570	(n)=(e)+(l)	$133,752,124	(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)			$215,381,695	(p) = (n) + (o)

New England Power Company
Annual Revenue Requirements of PTF Facilities
For Costs in 2010

POST-1996

🟨 Shading denotes an input

Line No.		Attachment F Reference *Section:*	NEP	Reference
	I. INVESTMENT BASE			
1	Transmission Plant	(A)(1)(a)	$725,670,117	Worksheet 5, line 1&2 column 5
2	General Plant	(A)(1)(b)	$3,362,178	Worksheet 5, line 3 column 5
3	Plant Held For Future Use	(A)(1)(c)	$502,454	Worksheet 5, line 5 column 5
4	Total Plant (Lines 1+2+3)		$729,534,749	
5	Accumulated Depreciation	(A)(1)(d)	($161,807,507)	Worksheet 5, line 8 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	($153,662,796)	Worksheet 5, line 11 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	$340,919	Worksheet 5, line 12 column 5
8	Other Regulatory Assets	(A)(1)(g)	$21,689,779	Worksheet 5, line 16 column 5
9	Net Investment (Line 4+5+6+7+8)		$436,095,144	
10	Prepayments	(A)(1)(h)	$0	Worksheet 5, line 17 column 5
11	Materials & Supplies	(A)(1)(i)	$2,183,689	Worksheet 5, line 18 column 5
12	Cash Working Capital	(A)(1)(j)	$3,864,692	Worksheet 5, line 25 column 5
13	Total Investment Base (Line 9+10+11+12)		$442,143,525	
	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	$58,192,048	Worksheet 3
15	Depreciation Expense	(B)	$15,934,886	Worksheet 6, line 3, column 5
16	Amortization of Loss on Reacquired Debt	(C)	$143,384	Worksheet 6, line 4, column 5
17	Investment Tax Credit	(D)	($193,658)	Worksheet 6, line 5, column 5
18	Property Tax Expense	(E)	$11,063,753	Worksheet 6, line 6, column 5
19	Payroll Tax Expense	(F)	$1,008,247	Worksheet 6, line 22, column 5
20	Operation & Maintenance Expense	(G)	$16,149,859	Worksheet 6, line 11, column 5
21	Administrative & General Expense	(H)	$14,767,674	Worksheet 6, line 21, column 5
22	Transmission Related Integrated Facilities Charge	(I)	$0	Attachment 4, line 6
23	Transmission Support Revenue	(J)	$0	Worksheet 8
24	Transmission Support Expense	(K)	$0	Worksheet 8
25	Transmission Related Expense from Generators	(L)	$0	
26	Transmission Related Taxes and Fees Charge	(M)	$0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	($1,897,688)	Attachment 7
28	Transmission Rents Received from Electric Property	(O)	($549,626)	Attachment 6
29	Total Revenue Requirements (Line 14 thru 28)		$114,618,878	

New England Power Company
Post 1996 Regional Network Service Revenue Requirement
For Test Year Ended 12/31/2010

🟨 Shading denotes an input

Line No.	Description	Attachment F Reference	Forecasted Amount $	Reference
1	Forecasted Revenue Requirements for Forecasted Transmission Plant Additions (FTPA)		$ 11,629,830	Line 6
2	Forecasted Revenue Requirements for Forecasted Transmission CWIP		7,503,415	Line 9
3	***Forecasted Transmission Revenue Requirements***		**$ 19,133,246**	Line 1 + Line 2
4	Forecasted Revenue Requirements for Forecasted Transmission Plant Additions (FTPA)	Appendix C iv	$ 73,388,000	Project Detail
5	Carrying Charge Factor (CCF)	Appendix C vi	15.84705%	Line 20
6	***Forecasted Revenue Requirements for FTPA***		**$ 11,629,830**	Line 4 * Line 5
7	Forecasted New England Power Company (NEP) NEEWS CWIP (FNCWIP)	Appendix C xiii	$ 53,588,131	Filing Workpaper
8	NEEWS NEP Cost of Capital Rate (NCOC)	Appendix C xiv	14.00201%	Workpaper 4
9	***Forecasted Revenue Requirements for FNCWIP***		**$ 7,503,415**	Line 7 * Line 8
	Derivation of Carrying Charge (CCF)			
10	Investment Return and Income Taxes	(A)	$56,123,135	Summary, Line 14
11	Depreciation Expense	(B)	15,934,886	Summary, Line 15
12	Amortization of Loss on Reacquired Debt	(C)	143,384	Summary, Line 16
13	Investment Tax Credit	(D)	(193,658)	Summary, Line 17
14	Property Tax Expense	(E)	11,063,753	Summary, Line 18
15	Payroll Tax Expense	(F)	1,008,247	Summary, Line 19
16	Operation & Maintenance Expense	(G)	16,149,859	Summary, Line 20
17	Administrative & General Expense	(H)	14,767,674	Summary, Line 21
18	Total Expenses (Lines 10 thru 17)		$114,997,280	
19	PTF Transmission Plant	(A)(1)(a)	$725,670,117	Summary, Line 1
20	***Carrying Charge Factor (FTPA)***		**15.84705%**	Line 18 / Line 19

New England Power Company

Annual Revenue Requirements
For Costs in 2010

▨ Shading denotes an input

	CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$410,350,000	35.93%	1.25%	0.45%	
PREFERRED STOCK	$1,111,700	0.10%	6.02%	0.01%	0.01%
COMMON EQUITY	$730,712,039	63.98%	11.64%	7.45%	7.45%
TOTAL INVESTMENT RETURN	$1,142,173,739	100.01%		7.91%	7.46%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0791

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

= (0.0746 +(($193,658) + $477,860) / $442,143,525) x 0.35)
(1 - 0.35)

= 0.0405153

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)* State Income Tax Rate
(1 - State Income Tax Rate)

= (0.0746 +(($193,658) + $477,860) / $442,143,525) + 0.0405153)* 0.059466
(1 - 0.059466)

= 0.0073189

(a)+(b)+(c) Cost of Capital Rate = **0.1269342**

	(PTF)	
INVESTMENT BASE	$442,143,525	From Worksheet 1
x Cost of Capital Rate	0.1269342	
= Investment Return and Income Taxes	**$56,123,135**	To Worksheet 1

Post 2003 PTF Investment Base w/ Incremental 100 bps:

Plant In-Service		$	326,955,170	From Attachment 1
Accumulated Depreciation			(71,799,431)	From Worksheets 5 & 7
Accumulate Deferred Income Taxes			(68,719,046)	From Worksheets 5 & 7
Total Post-2003 Investment		$	186,436,693	Calculated
Incremental ROE:	1.00%		0.00640	Calculated
Federal Income Taxes:			0.00345	Per Attachment F
State Income Taxes:			0.00062	Per Attachment F
Cost of Capital Rate			0.01047	
Incremental Return and Taxes on Post-2003 PTF Investment		**$**	**1,951,137**	

NEEWS CWIP w/ Incremental 125 bps:

New England Power NEEWS In-Service		$	15,743,593	PowerPlant Report
Accumulated Depreciation			(3,431,595)	From Worksheets 3 & 5
Accumulate Deferred Income Taxes			(3,308,970)	From Worksheets 3 & 5
Total New England Power NEEWS Investment		$	9,003,028	Calculated
Incremental ROE:	1.25%		0.00800	Calculated
Federal Income Taxes:			0.00431	Per Attachment F
State Income Taxes:			0.00078	Per Attachment F
Cost of Capital Rate			0.01308	
Incremental Return and Taxes on NEEWS PTF Investment		**$**	**117,776**	

NEEWS Allocation Factor

Total Transmission Investment	$1,484,361,243	Worksheet 7 Line 2
Total NEEWS In-Service - NEP	$15,743,593	PowerPlant Report
For Accumulated Depreciation	1.0606%	
NEEWS Allocation Factor	1.0606%	
Plant Allocation Factor	0.992566	Worksheet 7 Line 16
For Accumulated Deferred Income Taxes	1.0527%	

New England Power Company
Annual Revenue Requirements
For Costs in 2010

▨ Shading denotes an input

	CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$410,350,000	35.93%	1.25%	0.45%	
PREFERRED STOCK	$1,111,700	0.10%	6.02%	0.01%	0.01%
COMMON EQUITY	$730,712,039	63.98%	12.89%	8.25%	8.25%
TOTAL INVESTMENT RETURN	$1,142,173,739	100.01%		8.71%	8.26%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0871

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

= (0.0826 +(($193,658) + $477,860) / $442,143,525) x 0.35)
(1 - 0.35)

= 0.0448230

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)* State Income Tax Rate
(1 - State Income Tax Rate)

= (0.0826 +(($193,658) + $477,860) / $442,143,525) + 0.0448230)* 0.059466
(1 - 0.059466)

= 0.0080971

(a)+(b)+(c) Cost of Capital Rate = **0.1400201**

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					$725,670,117	Attachment 1, Page 1
2	Less: Plant Assoc. HVDC Leases					$0	Attachment 2
3	General Plant	$6,894,870	99.7459% (a)	$6,877,350	48.8877% (b)	$3,362,178	FERC Form 1 page 207.99
4	Total (line 1+2+ 3)			$6,877,350		$729,032,295	
5	Transmission Plant Held for Future Use	$1,027,771		$1,027,771	48.8877% (b)	$502,454	FERC Form 1 page 214.2,4,9
	Transmission Accumulated Depreciation						
6	Transmission Accumulated Depreciation	($325,966,071)		($325,966,071)	48.8877% (b)	($159,357,315)	FERC Form 1 page 219.25
7	General Plant Accumulated Depreciation	($5,024,647)	99.7459% (a)	($5,011,879)	48.8877% (b)	($2,450,192)	FERC Form 1 Page 219.28
8	Total (line 6+ 7)			($330,977,950)		($161,807,507)	
	Transmission Accumulated Deferred Taxes						
9	Accumulated Deferred Taxes (281-283)	($374,482,727)	99.2566% (c)	($371,698,822)	48.8877% (b)	($181,715,005)	FERC Form 1 page 113.62-64
10	Accumulated Deferred Taxes (190)	$57,810,678	99.2566% (c)	$57,380,913	48.8877% (b)	$28,052,209	FERC Form 1 page 111.82
11	Total (line 9+ 10)			($314,317,909)		($153,662,796)	
12	Transmission Loss on Reacquired Debt	$697,351	100.0000%	$697,351	48.8877% (b)	$340,919	FERC Form 1 Page 111.81c
	Other Regulatory Assets						
13	FAS 106	$0	99.7459% (a)	$0	48.8877% (b)	$0	
14	FAS 109 (Asset Account 182.3)	$44,366,536	100.0000%	$44,366,536	48.8877% (b)	$21,689,779	FERC Form 1 Page 232.7f
15	FAS 109 (Liability Account 254)	$0	100.0000%	$0	48.8877% (b)	$0	FERC Form 1 Page 278
16	Total (line 13+14+ 15)	$44,366,536		$44,366,536		$21,689,779	
17	Transmission Prepayments	$0	99.7459% (a)	$0	48.8877% (b)	$0	FERC Form 1 Page 111.57c
18	Transmission Materials and Supplies	$4,466,745		$4,466,745	48.8877% (b)	$2,183,689	FERC Form 1 Page 227.8c
19	Cash Working Capital						
20	Operation & Maintenance Expense					$16,149,859	Worksheet 1, Line 20
21	Administrative & General Expense					$14,767,674	Worksheet 1, Line 21
22	Transmission Support Expense					$0	Worksheet 8
23	Subtotal (line 20+21+22)					$30,917,533	
24						0.1250	x 45 / 360
25	Total (line 23 * line 24)					$3,864,692	

(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)
	Depreciation Expense						
1	Transmission Depreciation	$32,237,934		$32,237,934	48.8877%	$15,760,384	FERC Form 1 Page 336.7b
2	General Depreciation	$357,854	99.7459% (a)	$356,945	48.8877%	$174,502	FERC Form 1 Page 336.10b
3	Total (line 1+2)			$32,594,879		$15,934,886	
4	Amortization of Loss on Reacquired Debt	$293,292		$293,292	48.8877%	$143,384	FERC Form 1 Page 117.64c
5	Amortization of Investment Tax Credits	($396,129)		($396,129)	48.8877%	($193,658)	FERC Form 1 Page 266.8f - Footnote (f)
6	Property Taxes	$22,630,955		$22,630,955	48.8877%	$11,063,753	FERC Form 1 Page 263.10,17,23,28i - Footnote (e)
	Transmission Operation and Maintenance						
7	Operation and Maintenance	$60,951,521		$60,951,521	48.8877%	$29,797,797	FERC Form 1 Page 321.112b
8	Transmission of Electricity by Others - #565	$16,215,370		$16,215,370	48.8877%	$7,927,321	FERC Form 1 Page 321.96b
9	Load Dispatching - #561 (excl #561.3)	$11,701,546		$11,701,546	48.8877%	$5,720,617	FERC Form 1 Page 321.84-92b less 87b
10	** Station Expenses & Rents - #562 & #567	$0				$0	FERC Form 1 Page 321.93b & .98b
11	O&M less lines 8, 9 & 10	$33,034,605		$33,034,605	48.8877%	$16,149,859	
	Transmission Administrative and General						
12	Total Administrative and General	$32,504,326					FERC Form 1 Page 323.197b
13	Less: Property Insurance (#924)	($179,245)					FERC Form 1 Page 323.185b
14	Less: Regulatory Commission Expenses (#928)	$4,562,078					FERC Form 1 Page 323.189b
15	Less: General Advertising Expense (#930.1)	$0					FERC Form 1 Page 323.191b
16	Subtotal [line 12 minus (13 thru 15)]	$28,121,493	99.7459% (a)	$28,050,036	48.8877%	$13,713,017	
17	Plus: Property Insurance Allocated using Plant Allocator	($179,245)	99.2566% (c)	($177,912)	48.8877%	($86,977)	Line 13
18	Plus: Regulatory Commission Expense	$2,349,311	99.2566% (c)	$2,331,846	48.8877%	$1,139,986	Attachment 5 Line 6
19	Plus: Specifically identifed Trans. Related General Advertising Expense	$0		$0	48.8877%	$0	Line 15
20	Plus: Specifically identified Trans. Related Regulatory Expense	$3,370		$3,370	48.8877%	$1,648	FERC Form 1 Page 350.18c
21	Total A&G [line 16 + (17 thru 20)]	$30,294,929		$30,207,340		$14,767,674	
22	Payroll Tax Expense	$2,067,627	99.7459% (a)	$2,062,373	48.8877%	$1,008,247	FERC Form 1 Page 263.3,4i - Footnote (d)

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

Federal Unemployment	($37,667)
FICA	$2,105,294
Payroll Taxes	$0
State Unemployment	$0
Total	$2,067,627

(e) Property Taxes FF1, Page 263i

Massachusetts	$19,219,508
New Hampshire	$2,582,427
Vermont	$685,578
Maine	$0
Rhode Island	$143,442
Connecticut	$0
	$22,630,955

(a) Worksheet 7, Line 11
(b) Worksheet 7 Line 3
(c) Worksheet 7 Line 16
(d) Transmission Only - Payroll Taxes - Specifically identified in FERC From 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	$725,670,117	Attachment 1, Page 1
2	Total Transmission Investment	$1,484,361,243	FERC Form 1 Page 207.58g - Page 200.4b
3	Percent Allocation (Line 1/Line 2)	48.8877%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	$0	FERC Form 1 Page 354.14b
5	Affiliated Company Transmission Wages and Salaries	$22,444,501	General Ledger Query
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	$22,444,501	
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	$22,501,688	General Ledger Query
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	$22,501,688	
11	Percent Allocation (Line 6/Line 10)	99.7459%	
	Plant Allocation Factor		
12	Total Transmission Investment	$1,484,361,243	Line 2
13	plus Transmission-Related General Plant (Line 2 of Wkst. 3)	$6,877,350	Worksheet 5, Line 3, Column 3
14	= Revised Numerator (Line 12 + Line 13)	$1,491,238,593	
15	Total Plant in Service	$1,502,407,856	FERC Form 1 Page 207.104g - Page 200.4b
16	Percent Allocation (Line 14 / Line 16)	99.2566%	
	Post-2003 PTF Allocation Factor		
17	Total Post-2003 PTF Investment	$ 326,955,170	Attachment 1 Line 7
18	Total Transmission Investment	$1,484,361,243	Line 2
19	Percent Allocation (Line 17/Line 18) for Post-2003 to Total Tx	22.0267%	
20	Total Invst in Tx Plant/Total Plant in Serv *		
21	Post-2003 PTF Tx Plant/Total Invst in Tx Plant	21.8629%	Line 19 * Line 16

New England Power Company
Post-96 RNs Revenue Requirments
For Test Year Ended 12/31/2010

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.

			TOTAL	
Participant	**PTF Supporting Facilities**	**FERC Form 1 Reference**	**Revenues**	**Expenses**
			(a)	**(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	
EUA	345 kV Medway - Bridgewater 344 Line	Pg 330.5, Line 11	$0	
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**

Attachment 1

New England Power Company
2010 Informational Filing
PTF Plant Allocation

				Percent Pre/Post
1	2009	Pre-1997 PTF Transmission Plant	$350,766,082	
2	2009	Post-1996 PTF Transmission Plant	$640,156,098	
3	2010	Additions/Retirements	$86,100,929	
4	2010	Pre-1997 PTF Transmission Plant	$351,352,992	32.62%
5	2010	Post-1996 PTF Transmission Plant	$725,670,117	67.38%
6	2010	Total PTF Transmission Plant	$1,077,023,109	100.00%
7	2010	Post-2003 PTF Transmission Plant	$326,955,170	

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

Attachment 2

🟨 Shading denotes an input

GROSS PLANT ASSOC. WITH HVDC LEASES
2010

LINE NO		(HVDC) NHH/NEH LEASE
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 Hydo 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.

▨ Shading denotes an input

Attachment 3

New England Power Company
Determination of Book Depreciation on Equity AFUDC

		2010
1	Total Current Year Book Depreciation on Equity AFUDC	$980,344
2	Less: Specifically identified Transmission-Related	
	Tewksbury Line	$54,708
	Hydro-Quebec	$23,543
	MontaupTransmission 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
		$592,969
3	Total unidentified Book Depreciation on Equity AFUDC	$387,375
4	Plant Allocator Factor	99.2566%
5	Allocated Transmission Related Book Depreciation on Equity AFUDC	$384,495
6	Plus: Specifically Identified Transmission-Related Equity AFUDC	$592,969
7	Total Transmission-Related Equity AFUDC	$977,464
8	Post-96 PTF Allocation Factor	48.8877%
9	Transmission-Related Equity AFUDC	$477,860

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

🟨 Shading denotes an input

Attachment 4

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

		Narragansett **2010**	**MECO** **2010**
1	Total Integrated Facilities Charges	$0	$0
2	Total 2010 PTF Property	$0	$0
3	Total Transmission Plant in 2010	$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**		**$0**

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 2010 Regulatory Commission Expense

Line No.		2010	Source
1	Total Regulatory Commission Expense - NEP	$4,562,078	FERC Form1 Page 350.46d
2	Less: New Hampshire PUC Assessment	$57,482	FERC Form1 Page 350.2d
3	Less: Mass Emergency Fund	$0	FERC Form1 Page 350.7d
4	Less Mass DPU Special Assessment	$293,722	FERC Form1 Page 350.8d
5	Less: Utility Expenses	$1,861,563	FERC Form1 Page 350.46c
6	Total Federal Assessments	$2,349,311	Line 1 - (Line 2-5)

Attachment 6

Transmission Rents Received from Electric Property
New England Power Company

	2010
Revenues	$1,124,263
Plant Allocation Factor	100.00%
Transmission Allocated	$1,124,263
PTF Allocation	48.8877%
Total PTF Revenue	$549,626

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

Attachment 7

Revenue for Short-Term Transmission Service under the NEPOOL Tariff
New England Power Company

	2010
Revenues	$2,816,506
Post-96 PTF Percent	67.3774%
Total Post-96 PTF Revenue	$1,897,688

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

National Grid's 2011 Forecasted PTF Transmission Revenue Requirements
(in thousands)

				(A)	(B)	(C)=(A)x(B)	(D)	(E)=(C) / (D)
Line	Company	Project Name	RSP ID	Estimated PTF Plant In-Service (in thousands)	Annual Carrying Charge	Forecasted PTF Revenue Requirement (in thousands)	2010 12CP RNS Load	RNS Rate Impact $/kw-yr
1	NGRID	Wachusett 3rd 345kV Auto	944	$ 14,183	15.847%	$ 2,248		
2	NGRID	King Street, West Amesbury 115kV Line	783	$ 14,134	15.847%	$ 2,240		
3	NGRID	A127/B128 Refurbishment	1187	$ 13,597	15.847%	$ 2,155		
4	NGRID	Reconductor G-185N and Terminal Equipment Franklin Square	798/799 (a)	$ 4,658	15.847%	$ 738		
5	NGRID	A-127W Reconductor	940	$ 4,500	15.847%	$ 713		
6	NGRID	E205W - Reconductor and Rentension	939	$ 4,156	15.847%	$ 659		
7	NGRID	Carpenter Hill Breaker Replacement	924	$ 4,017	15.847%	$ 637		
8	NGRID	E205E Refurbishment	1152	$ 2,670	15.847%	$ 423		
9	NGRID	Kent County 345-115 Sub Phase I	788	$ 2,415	15.847%	$ 383		
10	NGRID	Millbury #2 - install new bay	673	$ 2,244	15.847%	$ 356		
11	NGRID	Pratts Junction 230kV & 115kV Ln	926/932 (a)	$ 1,375	15.847%	$ 218		
12	NGRID	Wakefield Junction Sub	777	$ 1,193	15.847%	$ 189		
13	NGRID	South Wrenthem Substation Upgrades	1109	$ 900	15.847%	$ 143		
14	NGRID	Terminal Upgrades at Drumrock, Chartley Pond and Brayton Point	786	$ 965	15.847%	$ 153		
15	NGRID	Line Reconductoring of M-139/N-140, S-145N/T-146N, Y-151, B-154N/C-155N, F-158N/S, and P-168.	Not Assigned yet	$ 600	15.847%	$ 95		
16	NGRID	315 Relay Upgrades at Brayton Point	N/A	$ 555	15.847%	$ 88		
17	NGRID	115kV Tap Woonsocket Sub New 115	484	$ 484	15.847%	$ 77		
18	NGRID	Golden Hills Modification	779	$ 453	15.847%	$ 72		
19	NGRID	Replace Steel Pole Bloomingdale Station	676	$ 189	15.847%	$ 30		
20	NGRID	I135S/J136S Reconductor	933	$ 100	15.847%	$ 16		
21	NGRID	NEEWS CWIP	Various	$ 53,588	14.002%	$ 7,503		
22	**Total NGRID**			**$ 126,976**		**$ 19,133**	**21,086.421**	**$ 0.9074**

(a) - Project is listed under multiple RSP numbers

New England Power Company
NEEWS Upgrades
S[illegible]ry of Estimated Return, Taxes and Depreciation with 100% CWIP in Rate Base *
For the Period January 1, 2011 - December 31, 2055
(Thousands of Dollars)

Line No.	Description	CY 2011	CY 2012	CY 2013	CY 2014	CY 2015	CY 2016	CY 2017	CY 2018	CY 2019	CY 2020
1	Gross Plant In Service (a)	$ 18,255	$ 79,447	$ 81,041	$ 81,041	$ 81,041	$ 159,779	$ 159,779	$ 159,779	$ 159,779	$ 159,779
2	Accumulated Depreciation (40 Years) (b)	$ 456	$ 2,443	$ 4,469	$ 6,495	$ 8,521	$ 12,515	$ 16,510	$ 20,504	$ 24,499	$ 28,493
3	Deferred Tax Liability on Accelerated Depreciation (c)	$ 88	$ 714	$ 2,126	$ 3,397	$ 4,515	$ 5,868	$ 8,142	$ 10,129	$ 11,872	$ 13,458
4	Net Plant In Service (d)	$ 17,711	$ 76,291	$ 74,446	$ 71,149	$ 68,006	$ 141,396	$ 135,128	$ 129,146	$ 123,409	$ 117,828
5	Year end CWIP (a)	$ 53,588	$ 7,757	$ 16,507	$ 47,282	$ 79,357	$ -	$ -	$ -	$ -	$ -
6	Rate Base (e)	$ 71,299	$ 84,048	$ 90,953	$ 118,431	$ 147,363	$ 141,396	$ 135,128	$ 129,146	$ 123,409	$ 117,828
7	Cost of Capital Rate (f)	14.0693%	14.0693%	14.0693%	14.0693%	14.0693%	14.0693%	14.0693%	14.0693%	14.0693%	14.0693%
8	Return and Taxes on NEEWS Upgrades (g)	$ 10,031	$ 11,825	$ 12,797	$ 16,662	$ 20,733	$ 19,893	$ 19,012	$ 18,170	$ 17,363	$ 16,578
9	Depreciation Expense (h)	$ 456	$ 1,986	$ 2,026	$ 2,026	$ 2,026	$ 3,994	$ 3,994	$ 3,994	$ 3,994	$ 3,994
10	Incremental Return, Taxes, and Depreciation on NEEWS Upgrades (i)	$ 10,488	$ 13,811	$ 14,823	$ 18,688	$ 22,759	$ 23,888	$ 23,006	$ 22,164	$ 21,357	$ 20,572
		$ 7,533	$ 598	$ 1,848	$ 6,195	$ 10,725	$ (1,916)	$ (1,844)	$ (1,776)	$ (1,711)	$ (1,649)

(a) Gross Plant balances and CWIP do not include AFUDC after January 1, 2011
(b) Pages 6 through 10, Line 3
(c) Pages 6 through 10, Line 13
(d) Line 1 - Line 2 - Line 3
(e) Line 4 + Line 5
(f) Page 10, Line 13
(g) Line 6 x Line 7
(h) Pages 6 through 10, Line 2
(i) Line 8 + Line 9

Disc Rate @ 8%	(10,046)	(10,363)	(317)
Disc Rate @ 9%	(10,672)	(10,363)	309
Disc Rate @ 11%	(11,485)	(10,363)	1,122
Disc Rate @ 12.89%	(11,882)	(10,363)	1,519

* For illustrative purposes only.
Minor variances due to rounding.

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 RNS Rates Effective June 1, 2011 through May 31, 2012

Revenue Requirements for Test Year: 2010

Customer: NHT

Customer's NABs Number:

Name of Participant responsible for customer's billing: NHT

DUNs number of Participant responsible for customer's billing:

	Line No.	Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	1	3,498,419	Pre-97 WS1, ln 14-22	7,192,900	Post-96 WS1, ln 14-2
Total of Attachment F - Section J - Support Revenue	2	0	Pre-97 WS1, ln 23	0	Post-96 WS1, ln 23
				0	
Total of Attachment F - Section K - Support Expense	3	533,030	Pre-97 WS1, ln 24	0	Post-96 WS1, ln 24
Total of Attachment F - Section (L through O)	4	(195)	Pre-97 WS1, ln 27	(365)	Post-96 WS1, ln 27
Sub Total - Sum (A through I) - J + K + (L through O)	5	4,031,254	Sum of above	7,192,535	Sum of above
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	6	N/A		$530,686	Post-96 WS8, ln. 3
Annual True-up (per Attachment C to Attachment F Implementation Rule)	7	$ 133,089	TU WS4, line 16	$ 1,764,637	TU WS4, line 16
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)	8	$ 4,164,343	lns. 5+6+7	$9,487,858	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) **$13,652,200** 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 Adde
Pre-'97 ATRR

▨ Shading denotes an input

Line No.		Attachment F Reference	NHT	Reference
	I. INVESTMENT BASE	Section:		
1	Transmission Plant	(A)(1)(a)	18,846,036	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)		18,846,036	
5	Accumulated Depreciation	(A)(1)(d)	6,726,543	Pre-97 WS3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	1,393,240	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)		10,726,253	
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)	203,958	Pre-97 WS3, line 24 column 5
13	Total Investment Base (Line 9+10+11+12)		10,930,211	
II.	REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	1,456,069	Pre-97 WS2
15	Depreciation Expense	(B)	594,277	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)	347,919	Pre-97 WS4, line 9 column 5
19	Payroll Tax Expense	(F)	1,518	Pre-97 WS4, line 33 column 5
20	Operation & Maintenance Expense	(G)	928,529	Pre-97 WS4, line 14 column 5
21	Administrative & General Expense	(H)	170,107	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)	533,030	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)	(195)	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)		**4,031,254**	

NOTES:

1. All amounts represent NHT's (or its affilitiates) 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 12/31/10	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	25,315,892	40.73%	4.22%	1.72%	
PREFERRED STOCK		0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY		36,833,344	59.27%	11.64%	6.90%	6.90%
TOTAL INVESTMENT RETURN	$	62,149,236	100.00%		8.62%	6.90%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0862

(b) Federal Income Tax = **(R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp) / PTF Inv. Base) x Federal Income Tax Rate)**
(1 - Federal Income Tax Rate)

= (0.0690 +(0 + 0) / 10,930,211) x 0.35)
(1 - 0.35)

= 0.0371538

(c) State Income Tax = **(R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp) / PTF Inv. Base) + Federal Income Tax)* State Income Tax Rate**
(1 - State Income Tax Rate)

= (0.0690 +(0 + 0) / 10,930,211) + 0.0371538)* 0.085
(1 - 0.085)

= 0.0098613

(a)+(b)+(c) Cost of Capital Rate = 0.1332151

		(PTF)	
INVESTMENT BASE	$	10,930,211	From Pre-97 WS1, line 13
x Cost of Capital Rate		0.1332151	
= Investment Return and Income Taxes		1,456,069	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

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Line No.		(1)	(2)	(3)	(4)	(5)	Reference for col (1)
		Total	Wage/Plant Allocation Factors	= (1)*(2) Transmission Allocated	Pre-Post PTF Allocation Factor	= (3)*(4) PTF Allocated	
	Transmission Plant						
1	Transmission Plant (Pre-'97 PTF)	18,846,036	Directly Assigned	18,846,036	Directly Assigned	18,846,036	Pre-97 WS 5, line 1
2	General Plant	0		0		0	
3	Total (line 1+2)					18,846,036	
4	Transmission Plant Held for Future Use	0		0		0	
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	6,726,543	Directly Assigned	6,726,543	Directly Assigned	6,726,543	Plant Data Support 5
6	General Plant Accum. Depreciation	0		0		0	
7	Total (line 5+6)					6,726,543	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	1,393,240	100.0000%	1,393,240	Directly Assigned (a)	1,393,240	Plant Data Support 5
9	Accumulated Deferred Taxes (190)	0		0		0	
10	Total (line 8+9)					1,393,240	
11	Transmission loss on Reacquired Debt	0		0		0	
	Other Regulatory Assets						
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)					0	
16	Transmission Prepayments (165)	0		0		0	
17	Transmission Materials and Supplies (154)	0		0		0	
18	Cash Working Capital						
19	Operation & Maintenance Expense					928,529	Pre-97 WS 1, Line 20
20	Administrative & General Expense					170,107	Pre-97 WS 1, Line 21
21	Transmission Support Expense					533,030	Pre-97 WS 7
22	Subtotal (line 19+20+21)					1,631,666	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					203,958	

Notes:

1. Depreciation Expense based on annual depreciation rate of 3.12% as approved by FERC in Docket No. ER04-714; Amount reflects expense recorded on FPL-NED's books Jan-May 2010 and on NHT's books Jun-Dec 2010

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

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🟨 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)
	Depreciation Expense						
1	Transmission Depreciation - Pre-'97 PTF	594,277	Directly Assigned	594,277	Directly Assigned	594,277	Data Support
2	General Depreciation	0		0		0	
3	Total (line 1+2)					594,277	
4	Amortization of Loss on Reacquired Debt	0		0		0	
5	Amortization of Investment Tax Credits	0		0		0	
	Property Taxes						
7	Transmission Property Taxes	1,102,455	100% (c)	1,102,455	31.5586% (a)	347,919	FPL Form 1
8	General Property Taxes	0		0		0	
9	Total (line 7+8)	1,102,455				347,919	
	Transmission Operation and Maintenance						
10	Operation and Maintenance (Directly Assigned to Transmission; Allocated to PTF)	2,942,238	Directly Assigned	2,942,238	31.5586% (a)	928,529	FPL 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	2,942,238				928,529	
	Transmission Administrative and General						
20	Administrative and General (see note 2)	539,018					FPL Form 1
21	less Property Insurance (#924) (see note 2)	30,315					FPL Form 1
22	less Regulatory Commission Expenses (#928) (see note 2)	82,233					FPL Form 1
23	less General Advertising Expense (#930.1)	0					
24	Subtotal [line 20 minus (21 thru 23)]	426,470	Directly Assign (b)	426,470	31.5586% (a)	134,588	
26	PLUS Property Insurance (see note 2)	30,315	100% (c)	30,315	31.5586% (a)	9,567	FPL Form 1
28	PLUS Regulatory Comm. Exp.: FERC Assessments (see note 2)	82,233	100% (c)	82,233	31.5586% (a)	25,952	FPL Form 1
29	PLUS Trans. Related General Advertising Expense	0		0		0	
30	Total A&G [line 20 plus (26 thru 29)]	539,018				170,107	
33	Payroll Tax Expense - Transmission Related Total	4,811	Directly Assign (b)	4,811	31.5586% (a)	1,518	FPL Form 1

Notes:

1. Depreciation Expense based on annual depreciation rate of 3.12% as approved by FERC in Docket No. ER04-714; Amount reflects expense recorded on FPL-NED's books Jan-May 2010 and on NHT's books Jun-
2. FPL-NED's / NHT's costs for Test Year directly assigned to transmission and allocated to pre-97/post-96 PTF.

References:

(a) Worksheet 5, line 3 (PTF/HTF Allocation Factor applicable to FPL-NED)
(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.		NHT	Reference
	PTF/HTF Transmission Plant Allocation Factor		
1	PTF Transmission Investment (Pre 1997)	18,846,036	Plant Data Support or Form 1
2	Total Transmission Investment	59,717,533	Plant Data Support or Form 1
3	Percent Allocation (Line 1/Line 2)	31.5586%	Line 1 / line 2
	PTF/HTF Transmission Plant Allocation Factor		
4	PTF Transmission Investment (Post-1996)	35,240,309	Plant Data Support or Form 1
5	Total Transmission Investment	59,717,533	Plant Data Support or Form 1
6	Percent Allocation (Line 4/Line 5)	59.0117%	Line 4 / line 5
	Transmission Wages and Salaries Allocation Factor		
7	Direct Transmission Wages and Salaries	0	Form 1
8	Affiliated Company Transmission Wages and Salaries	29,647	Form 1
9	Total Transmission Wages and Salaries (Line 7 + Line 8)	29,647	Sum Lines 7 + 8
10	Total Wages and Salaries	104,421	Form 1
11	Administrative and General Wages and Salaries	104,421	Form 1
12	Affiliated Company Wages and Salaries less A&G	29,647	Form 1
13	Total Wages and Salaries net of A&G (Line 10 - 11 + 12)	29,647	Sum Lines 10 + 11 + 12
14	Percent Allocation (Line 9/Line 13)	100.0000%	Line 9 / Line 13
	Plant Allocation Factor		
15	Total Transmission Investment	59,717,533	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)	59,717,533	Sum Lines 15 + 16
18	Total Plant in Service	59,717,533	Form 1
19	Percent Allocation (Line 17 / Line 18)	100.0000%	Line 17 / Line 18
	Pre-1997 and Post 1996 Transmission Plant		
20	PTF PRE 1997 Transmission Investment	18,846,036	Plant Data Support or Form 1
21	PTF POST 1996 Transmission Investment	35,240,309	Plant Data Support or Form 1
22	Total PTF Transmission Plant (Line 20+21)	54,086,345	Sum Lines 20 + 21
23	Percentage PTF PRE 1997 Transmission Investment (Line 20 / 22)	34.8444%	Line 20 / Line 22
24	Percentage PTF POST 1996 Transmission Investment (Line 21 / 22)	65.1556%	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

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🟨 Shading denotes an input

Line		FPL-NED
	"Affiliated" Transmission Wages and Salaries #560 - 573	
1	560	0
2	562	29,647
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)	29,647
12	Total "Affiliated" Wages and Salaries	60,446
	Less "Affiliated" Administrative and General Salaries #920 - 935	
13	920	6,426
14	921	0
15	923	0
16	925	0
17	926	0
18	928	24,373
19	930	0
20	935	0
21	Total Affilitated Administrative and General Salaries (13 thru 20)	30,799
22 = 12	Total "Affiliated" less A&G	29,647

Note: Affiliated Wages and Salaries reflect those of FPL-NED.

RTO-NE Regional Transmission Service
NHT's PTF Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO-NE Open Access Transmission Tariff
SED ON REHEARING ORDER BASE ROE SET AT 10.4% + 0.74 Bond Yield Adjustment + 0.5 RTO Adder
Pre-'97 ATRR

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.

🟨 Shading denotes an input

Participant	PTF Supporting Facilities	FERC Form 1	FPL NED / NHT		
			Revenues (a)	Expenses (b)	
NEP	345 kV NH/MA border - Tewksbury 394 line			212,677	See note
NU	345 kV 363, 369 and 394 Seabrook Lines			320,353	See note
		Total =	0	533,030	

Amount by which Support Expense exceeds Support Revenues 533,030
(To Worksheet 3, Line 21, Column 5)

Note: Amounts reflect Transmission Support Payments paid by FPL-NED Jan-May 2010 and by NHT Jun-Dec 2010 pursuant to the Seabrook Transmission Suport Agreement.

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

	(a)	(b)	
Line No.	**Revenue Source**	**Total Amount**	**Reference**
1	TOUT Revenues	$560	ISO-NE
2	Post-96 PTF Plant Allocator	65.2%	Post-96 WS5, line 24
3	Pre-97 PTF Plant Allocator	34.8%	Post-96 WS5, line 23
4	Post-96 Revenues	$365	Line 1 x Line 2
5	Pre-97 Revenues	$195	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

Line No.		Attachment F Reference	NHT	Reference
	I. INVESTMENT BASE	Section:		
1	Transmission Plant	(A)(1)(a)	35,240,309	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)		35,240,309	
5	Accumulated Depreciation	(A)(1)(d)	2,465,505	Post-96 WS 3, line 8, column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	4,659,540	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)		28,115,264	
10	Prepayments	(A)(1)(h)	0	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)	256,793	Post-96 WS 3, line 27, column 5
13	Total Investment Base (Line 9+10+11+12)		28,372,057	
	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes (Post-'96 / Pre-'04 Investments)	(A)	3,779,586	Post-96 WS2
15	Incentive Investment Return and Income Taxes (Eligible Investments)	(A)	0	Post-96 WS2A
16	Depreciation Expense	(B)	705,550	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)	650,577	Post-96 WS4, line 9 column 5
20	Payroll Tax Expense	(F)	2,839	Post-96 WS4, line 32 column 5
21	Operation & Maintenance Expense	(G)	1,736,265	Post-96 WS4, line 14 column 5
22	Administrative & General Expense	(H)	318,083	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)	(365)	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)		**7,192,535**	

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 12/31/10	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	25,315,892	40.73%	4.22%	1.72%	
PREFERRED STOCK		0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY (see note)		36,833,344	59.27%	11.64%	6.90%	6.90%
TOTAL INVESTMENT RETURN	$	62,149,236	100.00%		8.62%	6.90%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0862

(b) Federal Income Tax	=	(	R.O.E. +	(	PTF Inv. (Tax Credit	+	Eq. AFUDC of Deprec. Exp	) /	PTF Inv. Base)	x	Federal Income Tax Rate	)	
		(	1							-	Federal Income Tax Rate	)	
	=	(	0.0690	+(	0	+	0	) /	2,030,118)	x	0.35	)	
		(	1							-	0.35	)	
	=		0.0371538										
(c) State Income Tax	=	(	R.O.E. +	(	PTF Inv. (Tax Credit	+	Eq. AFUDC of Deprec. Exp	) /	PTF Inv. Base)	+	Federal Income Tax	)*	State Income Tax Rate
		(	1							-	State Income Tax Rate	)	
	=	(	0.0690	+(	0	+	0	) /	2,030,118)	+	0.0371538	)*	0.085
		(	1							-	0.085	)	
	=		0.0098613										

(a)+(b)+(c) Cost of Capital Rate = 0.1332151

		(PTF)	
INVESTMENT BASE	$	28,372,057	From Post-96 WS 1, line 13
x Cost of Capital Rate		0.1332151	
= Investment Return and Income Taxes		3,779,586	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 2010 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
Post-2003 Investment Return Adder

🟨 Shading denotes an input

		CAPITALIZATION 12/31/04	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	25,315,892	40.73%	4.22%	NA	NA
PREFERRED STOCK		0	0.00%	0.00%	NA	NA
COMMON EQUITY		36,833,344	59.27%	1.00%	0.59%	0.59%
TOTAL INVESTMENT RETURN	$	62,149,236	100.00%		0.59%	0.59%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0059

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp) / PTF Inv. Base) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

= (0.0059 +(0 + 0) / 2,030,118) x 0.35) / (1 - 0.35)

= 0.0031769

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp) / PTF Inv. Base) + Federal Income Tax)* State Income Tax Rate / (1 - State Income Tax Rate)

= (0.0059 +(0 + 0) / 2,030,118) + 0.0031769)* 0.085 / (1 - 0.085)

= 0.0008432

(a)+(b)+(c) Cost of Capital Rate = 0.0099201

		(PTF)
NEW INVESTMENT BASE SUBJECT TO INCENTIVE ADDER	$	
Post 2003 / Pre-2009 PTF Transmission Plant In RSP		0
less Accum. Depreciation Reserve - Post-2003 / Pre-2009 RSP Investment		0
less Accum. Deferred Taxes - Post-2003 / Pre-2009 RSP Investment		0
Post-2003 / Pre-2009 INVESTMENT BASE In RSP Eligible for Incentive ROE		0
Post-2009 PTF Transmission Plant Eligilble for Incentive ROE per FERC Order		0
less Accum. Depreciation Reserve - Post-2009 Investment Eligible for Incentive ROE		0
less Accum. Deferred Taxes - Post-2009 RSP Investment		0
Post-2009 INVESTMENT BASE In RSP Eligible for Incentive ROE		0
Total Investment Eligible for ROE Adder		$ -
x Cost of Capital Rate		0.0099201
= Investment Return and Income Taxes		$ -

To Worksheet 1, Line 15

Note: All amounts represent FPL'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

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)
	Transmission Plant						
1	Transmission Plant (Post-'96 PTF)	35,240,309	Directly Assigned	35,240,309	Directly Assigned	35,240,309	Post-96 WS 5, line 4
2	General Plant	0				0	
3	Total (line 1+2)					35,240,309	
4	Transmission Plant (Post-'03 PTF incl. in line 1)	NA	Directly Assigned	NA	Directly Assigned	NA	Post-96 WS 5, line 26
5	Transmission Plant Held for Future Use	0		0		0	
	Transmission Accumulated Depreciation						
6	Transmission Accum. Depreciation (note 1)	2,465,505	Directly Assigned	2,465,505	Directly Assigned	2,465,505	Plant Data Support 5
7	General Plant Accum. Depreciation	0		0		0	
8	Total (line 6+7)					2,465,505	
			0				
9	Transmission Accum. Depreciation Post-2003 Investments (note 2)	NA	0	NA	0	NA	Note 2
	Transmission Accumulated Deferred Taxes						
10	Accumulated Deferred Taxes (281-283) (FPL-NED Direct Assignment)	4,659,540	100%	4,659,540	Directly Assigned (a)	4,659,540	Plant Data Support 5
11	Accumulated Deferred Taxes (190)	0		0		0	
12	Total (line 10+11)					4,659,540	
13	Accumulated Deferred Taxes Post-2003 Investments (note 2)	NA	NA	NA	NA	(b) NA	Note 2
14	Transmission loss on Reacquired Debt	0		0		0	
	Other Regulatory Assets						
15	FAS 106	0		0		0	
16	FAS 109	0		0		0	
17	Other Regulatory Liabilities (254)	0		0		0	
18	Total (line 15+16+17)					0	
19	Transmission Prepayments (165)	0		0		0	
20	Transmission Materials and Supplies (154)	0		0		0	
21	Cash Working Capital						
22	Operation & Maintenance Expense					1,736,265	Post-96 WS 1, Line 21
23	Administrative & General Expense					318,083	Post-96 WS 1, Line 22
24	Transmission Support Expense					0	Post-96 WS 7
25	Subtotal (line 22+23+24)					2,054,348	
26						0.125	x 45 / 360
27	Total (line 25 * line 26)					256,793	

Notes/ References:

1. Depreciation Expense based on annual depreciation rate of 3.12% as approved by FERC in Docket No. ER04-714; Amount reflects expense recorded on FPL-NED's books Jan-May 2010 and on NHT's books Jun-Dec 2010.
2. Accumuated Depreciation ahd Deffered Taxes for Post-2003 Investment not shown because NHT does not have any Post-2003 Investments (2004-2008) eligible for the incentive ROE.

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	Transmission Depreciation - Post-'96 PTF (Note 1)	705,550	100%	705,550	Directly Assigned	705,550	Data Support 5
2	General Depreciation	0		0		0	
3	Total (line 1+2)					705,550	
4	Amortization of Loss on Reacquired Debt	0		0		0	
5	Amortization of Investment Tax Credits	0		0		0	
	Property Taxes						
7	Transmission Property Taxes (see note 2)	1,102,455	100%	1,102,455	59.0117% (a)	650,577	Form 1
8	General Property Taxes	0		0		0	
9	Total (line 7+8)	1,102,455				650,577	
	Transmission Operation and Maintenance						
10	Operation and Maintenance (Directly Assigned to Transmission; Allocated to PTF)	2,942,238	Directly Assigned	2,942,238	59.0117% (a)	1,736,265	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	2,942,238				1,736,265	
	Transmission Administrative and General						
15	Administrative and General (see note 2)	539,018					Form 1
16	less Property Insurance (#924) (see note 2)	30,315					Form 1
17	less Regulatory Commission Expenses (#928) (see note 2)	82,233					Form 1
18	less General Advertising Expense (#930.1)	0					
19	Subtotal [line 15 minus (16 thru 18)]	426,470	Directly Assign (b)	426,470	59.0117% (a)	251,667	
25	PLUS Property Insurance (see note 2)	30,315	100% (c)	30,315	59.0117% (a)	17,889	Form 1
26	PLUS Regulatory Comm. Exp.: FERC Assessments (see note 2)	82,233	100% (c)	82,233	59.0117% (a)	48,527	Form 1
27	PLUS Trans. Related General Advertising Expense	0		0		0	
28	Total A&G [line 19 plus (25 thru 27)]	539,018		0	59.0117% (a)	318,083	
32	Payroll Tax Expense - Tranmission Related (see note 2)	4,811	Directly Assign (b)	4,811	59.0117% (a)	2,839	Form 1

Notes:

1. Depreciation Expense based on annual depreciation rate of 3.12% as approved by FERC in Docket No. ER04-714; Amount reflects expense recorded on FPL-NED's books Jan-May 2010 and on NHT's books Jun-Dec 2010.
2. FPL-NED's & NHT's costs for Test Year directly assigned to transmission and allocated to pre-97/post-96 PTF.

Reference (a) Worksheet 5, line 3 (PTF/HTF Allocation Factor applicable to FPL-NED)
(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
	PTF/HTF Transmission Plant Allocation Factor		
1	PTF Transmission Investment (Pre 1997)	18,846,036	Plant Data Support 1 or Form 1
2	Total Transmission Investment	59,717,533	Plant Data Support 1 or Form 1, and Plant Data 4 (See note 1)
3	Percent Allocation	31.5586%	Line 1 / line 2
	PTF/HTF Transmission Plant Allocation Factor		
4	PTF Transmission Investment (Post-1996)	35,240,309	Plant Data Support 1 and Plant Data Support 4 (See Note 2)
5	Total Transmission Investment	59,717,533	Plant Data Support or Form 1
6	Percent Allocation	59.0117%	Line 4 / line 5
	Transmission Wages and Salaries Allocation Factor		
7	Direct Transmission Wages and Salaries	0	Form 1
8	Affiliated Company Transmission Wages and Salaries	29,647	Form 1
9	Total Transmission Wages and Salaries	29,647	Sum Lines 7 + 8
10	Total Wages and Salaries	104,421	Form 1
11	Administrative and General Wages and Salaries	104,421	Form 1
12	Affiliated Company Wages and Salaries less A&G	29,647	
13	Total Wages and Salaries net of A&G	29,647	Sum Lines 10 + 11 + 12
14	Percent Allocation	100.0000%	Line 9 / Line 13
	Plant Allocation Factor		
15	Total Transmission Investment	59,717,533	Form 1
16	plus Transmission-Related General Plant	0	
17	Total Transmission Related Investment	59,717,533	Sum Lines 15 + 16
18	Total Plant in Service	59,717,533	Form 1
19	Percent Allocation	100.0000%	Line 17 / Line 18
	Pre-1997 and Post 1996 Transmission Plant		
20	PTF PRE 1997 Transmission Investment	18,846,036	Plant Data Support or Form 1
21	PTF POST 1996 Transmission Investment	35,240,309	Plant Data Support or Form 1
22	Total PTF Transmission Plant	54,086,345	Sum Lines 20 + 21
23	Percentage PTF PRE 1997 Transmission Investment	34.8444%	Line 20 / Line 22
24	Percentage PTF POST 1996 Transmission Investment	65.1556%	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	59,717,533	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	59,717,533	
31	Post-2009 PTF in RSP as Percentage of Total Transmission Investment	0	

Notes

1 Total Plant In-Service reflects Total Plant In-Service adjusted to remove an amount reflecting a Captial Contribution to be paid by NHT's Local Customer as a Direct Assignment Facilities Charge associated with upgraded generator interconnection and LNS facilities.

2 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 FPLC-08-TO1 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 / FPL-NED
	"Affiliated" Transmission Wages and Salaries #560 - 573	
1	560	0
2	562	29,647
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)	29,647
12	Total "Affiliated" Wages and Salaries	60,446
	Less "Affiliated" Administrative and General Salaries #920 - 935	
13	920	6,426
14	921	0
15	923	0
16	925	0
17	926	0
18	928	24,373
19	930	0
20	935	0
21	Total Affilitated Administrative and General Salaries (13 thru 20)	30,799
22 = 12	Total "Affiliated" less A&G	29,647

Note: All amounts represent NHT's 88.22889% ownership share in the Seabrook Substation.

Pursuant to the FERC-approved Settlement Agreement in Docket No. ER04-714, FPL (affiliate of NHT) maintained FPL-NED's costs as thouugh it was a stand-alone company and all labor related charges recorded as FPL-NED costs were based on actual hours and wages paid to those FPL personnel working directly for FPL-NED. Therefore, the total Wages and Salaries reported above exclude all non-FPL-NED related wages and salaries.

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 0
(To Post-96 WS3, Line 24, Column 5)

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

Line No.		Period	Attachment F Reference Section:	NHT	Reference
	I. FORECASTED TRANSMISSION REVENUE REQUIREMENTS				
1	Forecasted Transmission Plant Additions	2011	Appendix C	$2,600,000	Note 1
2	Carrying Charge Factor		Appendix C	20.41%	Line 15
3	Total Forecasted Revenue Requirements (Lines 1*2)			$530,686	Line 1 x Line 2
	II. CARRYING CHARGE FACTOR				
4	Investment Return and Income Taxes (Post-'96 / Pre-'04 Investments)		(A)	$3,779,586	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)	705,550	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)	650,577	Post-96, WS 1, line 19
10	Payroll Tax Expense		(F)	2,839	Post-96, WS 1, line 20
11	Operation & Maintenance Expense		(G)	1,736,265	Post-96, WS 1, line 21
12	Administrative & General Expense		(H)	318,083	Post-96, WS 1, line 22
13	Total Expenses (Lines 4 thru 12)			$7,192,900	Sum lines 4 thru 12
14	PTF Transmission Plant		(A)(1)(a)	$35,240,309	Post-96, WS 1, line 4
15	Carrying Charge Factor (Lines 13/14)			20.41%	Line 13 / Line 15

Note:

1 Forecast Plant Addition includes following projects expected to be placed in service / closed to books by 12/31/11:

- Completion of Reliability Upgrade Project	$ 1,600,000
- Replace TTR6 Switch	$ 1,000,000
Total Estimated Capital Additions placed in service during 2011	$ 2,600,000

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

	(a)	(b)	
Line No.	**Revenue Source**	**Total Amount**	**Reference**
1	TOUT Revenues	$560	ISO-NE
2	Post-96 PTF Plant Allocator	65.2%	Post-96 WS5, line 24
3	Pre-97 PTF Plant Allocator	34.8%	Post-96 WS5, line 23
4	Post-96 Revenues	$365	Line 1 x Line 2
5	Pre-97 Revenues	$195	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

Line No.		Attachment F Reference Section:	PRE97	POST 1996	Reference
	I. INVESTMENT BASE				
1	Transmission Plant		$ 18,846,036	$ 35,240,309	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)		$ 18,846,036	$ 35,240,309	Per-97 and Post-96 WS1
5	Accumulated Depreciation	Appendix C	$ 6,726,543	$ 2,465,505	Per-97 and Post-96 WS1
6	Accumulated Deferred Income Taxes	Appendix C	1,393,240	4,659,540	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)		$ 10,726,253	$ 28,115,264	Per-97 and Post-96 WS1
10	Prepayments	Appendix C	0	0	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	203,958	256,793	Per-97 and Post-96 WS1
13	Total Investment Base (Line 9+10+11+12)		$ 10,930,211	$ 28,372,057	Per-97 and Post-96 WS1
	II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	Appendix C	$ 1,456,069	$ 3,779,586	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	594,277	705,550	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	347,919	650,577	Per-97 and Post-96 WS1
20	Payroll Tax Expense	Appendix C	1,518	2,839	Per-97 and Post-96 WS1
21	Operation & Maintenance Expense	Appendix C	928,529	1,736,265	Per-97 and Post-96 WS1
22	Administrative & General Expense	Appendix C	170,107	318,083	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	533,030	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	(195)	(365)	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 2010 Form 1 Total Revenue Requirements (Line 14 thru 28)		$ 4,031,254	$ 7,192,535	Per-97 and Post-96 WS1
31	As-Filed / Billed June 1, 2009 - May 31, 2010 less True-Up component		$ 3,902,457	$ 5,484,806	June 2, 2009 RNS Rates
32	**True-Up (Over) / Under Collection** (line 30-31)		**$ 128,797**	**$ 1,707,729**	line 30 less line 31

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

	Undercollection / (Overcollection)	
PRE97	$ 128,797	Undercollection
Post1996	$ 1,707,729	Undercollection

Line No.	Initial Billing Period	PRE97 Balance	POST 1996 Balance	FERC Monthly Interest Rate	PRE97 Interest	POST 1996 Interest		
1	June 2010	$ 128,796.83	$ 1,707,729	0.27%	$ 347.75	$ 4,611		
					-			
2	July 2010	129,144.58	1,712,340.16	0.28%	361.60	4,794.55		
3	August 2010	129,144.58	1,712,340.16	0.28%	361.60	4,794.55		
4	September 2010	129,144.58	1,712,340.16	0.27%	348.69	4,623.32		
					-			
6	October 2010	130,216.48	1,726,552.59	0.28%	364.61	4,834.35		
7	November 2010	130,216.48	1,726,552.59	0.27%	351.58	4,661.69		
8	December 2010	130,216.48	1,726,552.59	0.28%	364.61	4,834.35		
					-			
9	January 2011	131,297.28	1,740,882.97	0.28%	367.63	4,874.47		
10	February 2011	131,297.28	1,740,882.97	0.25%	328.24	4,352.21		
11	March 2011	131,297.28	1,740,882.97	0.28%	367.63	4,874.47		
					-			
12	April 2011	132,360.78	1,754,984.13	0.27%	357.37	4,738.46		
13	May 2011	132,360.78	1,754,984.13	0.28%	370.61	4,913.96		
14			Total Interest		$ 4,292	$ 56,907		
15			True-Up		$ 128,797	$ 1,707,729		
16			**Total TU & Int**		**$ 133,089**	**$ 1,764,637**	**$ 1,897,725**	**Under Collectior**

CALCULATION OF PRE 1997 AND POST 1996
PLANT IN SERVICE AND ACCUMULATED DEPRECIATION
AT DECEMBER 31,2004
AT DECEMBER 31,2005
At DECEMBER 31, 2006
At DECEMBER 31, 2007

	Pre - 97	**Post - 96**					**Total Pre 97 and Post 96**
		Pre -2004	**2004 Additions**	**2005 Additions**	**2006 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	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
2005							
Additions							
Jan - August				0		-	-
September				255,084		255,084	255,084
October				0		-	-
November				350,072		350,072	350,072
December				(704)		(704)	(704)
Retirements and Removal							-
Jan - August	0					-	-
September	132,343					-	132,343
October	0					-	-
November	268,687					-	268,687
December	0					-	-
Monthly Depreciation Expense							
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				
Depreciation Expense on 2004 Balance	**686,282**	**62,698**	**991**			**63,689**	**749,971**
Add:							
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			
Deprec Exp.on Sept Addition/Retirement	**(1,376)**			**2,653**		**2,653**	**1,277**
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			
Deprec Exp.on Nov Addition/Retirement	**(1,048)**			**1,365**		**1,365**	**317**
December Additions/Retirements	0			(704)			
Monthly Depreciation Rate = .0312 /12				0.0026			
Monthly Depreciation Expense				(2)			
December				0.5			
Deprec Exp.on Dec Addition/Retirement				**(1)**		**(1)**	(1)
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		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	**14,190,023**	**1,296,158**	**29,822**	**600,434**			**1,926,413**	**16,116,437**
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	**13,518,519**	**1,233,460**	**28,831**	**581,575**	**392,048**		**2,235,914**	**15,754,433**
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**		**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	**669,493**	**62,698**	**991**	**18,859**	**12,437**		**94,985**	
Add:								
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	
Add:								
April Additions/Retirements						(964)		
Monthly Depreciation Rate = .0312 /12						0.0026		
Monthly Depreciation Expense						(2.51)		
April - December						8.5		
Deprec Exp.on April Addition/Retirement						**(21)**	(21)	
Add:								
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	
Add:								
Jun 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	
Add:								
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	
Add:								
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	
Add:								
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	
Add:								
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 Post - 96**	**Total Pre 97 and Post 96 (PTF)**
		Pre -2004	**2004 Additions**	**2005 Additions**	**2006 Additions**	**2007 Additions**	**2008 Additions**		
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			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	**665,310**	**62,698**	**991**	**18,859**	**12,437**	**14,651**		**109,636**	
Add:									
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							**13**	13	
Add:									
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							**32**	32	
Add:									
March Additions/Retirements	-						840		
Monthly Depreciation Rate = .0312 /12	0.0026						0.0026		
Monthly Depreciation Expense	-						2.18		
March - December	7.5						9.5		
Deprec Exp.on April Addition/Retirement	-						**21**	21	
Add:									
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							**53**	53	
Add:									
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							**4**	4	
Add:									
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							**286**	286	
Add:									
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							**594**	594	
Add:									
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**	**775,948**

YEAR 2009	**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**				**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	(2,998)									
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	9.5							9.5		
Deprec Exp.on April Addition/Retirement	(539)							**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)		

	Pre - 97	Post - 96									Total Pre 97 and Post 96
		Pre -2004	2004 Additions	2005 Additions	2006 Additions					Total Post - 96	
Plant in Service at 12/31/03	21,996,233	2,009,542	-	-						2,009,542	24,005,775
Oct - December	2.5							2.5			
Deprec Exp.on Oct. Addition/Retirement	(12,619)							**(364)**		**(364)**	
Add:											
Nov Additions/Retirements	-							1,117			
Monthly Depreciation Rate = .0312 /12	0.0026							0.0026			
Monthly Depreciation Expense	-							2.90			
Nov - December	1.5							1.5			
Deprec Exp.on Oct. Addition/Retirement	-							**4**		**4**	
Add:											
Dec Additions/Retirements	-							11,978			
Monthly Depreciation Rate = .0312 /12	0.0026							0.0026			
Monthly Depreciation Expense	-							31.14			
December	0.5							0.5			
Deprec Exp.on Dec Addition/Retirement	-							**16**		**16**	
Plant In Service at 12/31/09	**19,303,754**	**2,009,542**	**31,762**	**604,451**	**398,628**	**469,590**	**113,302**	**1,340,187**		**4,967,462**	**24,271,216**
Accumulated provision for Depreciation at 12/31/09	**6,724,974**	**964,175**	**5,905**	**79,453**	**43,891**	**36,418**	**4,537**	**32,585**		**1,166,965**	**7,891,939**
Net Plant NBV @ 12/31/09	**12,578,780**	**1,045,367**	**25,858**	**524,999**	**354,737**	**433,172**	**108,765**	**1,307,601**		**3,800,497**	**16,379,278**
Depreciation expense 2009	**650,426**	**62,698**	**991**	**18,859**	**12,437**	**14,651**	**3,535**	**32,585**		**145,756**	**796,182**

YEAR 2010	**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**	**2010 Additions**	**Total Post - 96**	
Plant In Service at 12/31/09	**19,303,754**	**2,009,542**	**31,762**	**604,451**	**398,628**	**469,590**	**113,302**	**1,340,187**	**-**	**4,967,462**	**24,271,216**
Accumulated provision for Depreciation											

CALCULATION OF PRE 1997 AND POST 1996
PLANT IN SERVICE AND ACCUMULATED DEPRECIATION
AT DECEMBER 31,2004
AT DECEMBER 31,2005
At DECEMBER 31, 2006
At DECEMBER 31, 2007

	Pre - 97	Post - 96					Total Pre 97 and Post 96	Amount per FERC FORM 1 Footnote
		Pre -2004	2004 Additions	2005 Additions	2006 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	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	749,930
Plant In Service at 12/31/04	21,996,233	2,009,542	31,762	-		2,041,304	24,037,537	24,037,538
Accumulated provision for Depreciation at 12/31/04	7,122,351	650,687	950	-		651,636	7,773,988	7,773,993
Net Plant NBV @ 12/31/04	14,873,882	1,358,855	30,813	-		1,389,668	16,263,550	16,263,545
2005								
Additions								
Jan - August				0		-	-	
September				255,084		255,084	255,084	
October				0		-	-	
November				350,072		350,072	350,072	
December				(704)		(704)	(704)	
Retirements and Removal							-	
Jan - August	0					-	-	
September	132,343					-	132,343	
October	0					-	-	
November	268,687					-	268,687	
December	0					-	-	
Monthly Depreciation Expense								
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					
Depreciation Expense on 2004 Balance	**686,282**	**62,698**	**991**			**63,689**	**749,971**	
Add:								
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				
Deprec Exp.on Sept Addition/Retirement	**(1,376)**			**2,653**		**2,653**	**1,277**	
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				
Deprec Exp.on Nov Addition/Retirement	**(1,048)**			**1,365**		**1,365**	**317**	
December Additions/Retirements	0			(704)				
Monthly Depreciation Rate = .0312 /12				0.0026				
Monthly Depreciation Expense				(2)				
December				0.5				
Deprec Exp.on Dec Addition/Retirement				**(1)**		**(1)**	(1)	
Plant In Service at 12/31/05	**21,595,203**	**2,009,542**	**31,762**	**604,451**		**2,645,756**	**24,240,959**	**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**	**8,124,527**
Net Plant NBV @ 12/31/05	**14,190,023**	**1,296,158**	**29,822**	**600,434**		**1,926,413**	**16,116,437**	**16,116,432**
						-		
	Pre - 97 (PTF)	**Post - 96 (PTF)**					**Total Pre 97 and Post 96 (PTF)**	**Amount per FERC FORM 1 Footnote**
		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**	**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**	**8,124,527**
Net Plant NBV @ 12/31/05	**14,190,023**	**1,296,158**	**29,822**	**600,434**		**1,926,413**	**16,116,437**	**16,116,432**
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**	**24,502,500**
Accumulated provision for Depreciation at 12/31/06	**7,939,596**	**776,082**	**2,932**	**22,876**	**6,580**	**808,470**	**8,748,066**	**8,748,068**
Net Plant NBV @ 12/31/06	**13,518,519**	**1,233,460**	**28,831**	**581,575**	**392,048**	**2,235,914**	**15,754,433**	**15,754,432**
Depreciation expense 2006	**671,504**					**89,127**	**760,632**	**760,629**

YEAR 2007	**Pre - 97 (PTF)**	**Post - 96 (PTF)**						**Total Pre 97 and Post 96 (PTF)**	**FERC FORM 1 Footnote**
		Pre -2004	**2004 Additions**	**2005 Additions**	**2006 Additions**	**2007 Additions**	**Total Post - 96**		
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**	**24,502,500**
Accumulated provision for Depreciation at 12/31/06	**7,939,596**	**776,082**	**2,932**	**22,876**	**6,580**		**808,470**	**8,748,066**	**8,748,068**
Net Plant NBV @ 12/31/06	**13,518,519**	**1,233,460**	**28,831**	**581,575**	**392,048**		**2,235,914**	**15,754,433**	**15,754,432**
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**	24,502,500
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	**669,493**	**62,698**	**991**	**18,859**	**12,437**		**94,985**		
Add:									
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		
Add:									
April Additions/Retirements						(964)			
Monthly Depreciation Rate = .0312 /12						0.0026			
Monthly Depreciation Expense						(2.51)			
April - December						8.5			
Deprec Exp.on April Addition/Retirement						**(21)**	(21)		
Add:									
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		
Add:									
Jun 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		
Add:									
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		
Add:										
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		
Add:										
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		
Add:										
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**	**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**	**9,382,960**
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**	**15,455,042**
Depreciation expense 2007	**666,878**							**102,101**	**768,979**	**768,979**
YEAR 2008	**Pre - 97 (PTF)**	**Post - 96 (PTF)**							**Total Pre 97 and Post 96 (PTF)**	**FERC FORM 1 Footnote**
		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**	**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**	**9,382,960**
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**	**15,455,042**
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**	24,502,500
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	**665,310**	**62,698**	**991**	**18,859**	**12,437**	**14,651**		**109,636**		
Add:										
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							**13**	13		
Add:										
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							**32**	32		
Add:										
March Additions/Retirements	-						840			
Monthly Depreciation Rate = .0312 /12	0.0026						0.0026			
Monthly Depreciation Expense	-						2.18			
March - December	7.5						9.5			
Deprec Exp.on April Addition/Retirement	-						**21**	21		
Add:										
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							**53**	53		
Add:										
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							**4**	4		
Add:										
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							**286**	286		
Add:										
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							**594**	594		
Add:										

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**	**24,951,304**
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**	**10,158,908**
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**	**14,792,396**
Depreciation expense 2008	**665,310**								**110,638**	**775,948**	**775,948**

YEAR 2009	**Pre - 97 (PTF)**	**Post - 96 (PTF)**								**Total Pre 97 and Post 96 (PTF)**	**FERC FORM 1 Footnote**
		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**	**24,951,304**
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**	**10,158,908**
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**	**14,792,396**
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	(2,998)										
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	9.5							9.5			
Deprec Exp.on April Addition/Retirement	(539)							**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)				
Oct - December	2.5							2.5				
Deprec Exp.on Oct. Addition/Retirement	(12,619)							**(364)**		**(364)**		
Add:												
Nov Additions/Retirements	-							1,117				
Monthly Depreciation Rate = .0312 /12	0.0026							0.0026				
Monthly Depreciation Expense	-							2.90				
Nov - December	1.5							1.5				
Deprec Exp.on Oct. Addition/Retirement	-							**4**		**4**		
Add:												
Dec Additions/Retirements	-							11,978				
Monthly Depreciation Rate = .0312 /12	0.0026							0.0026				
Monthly Depreciation Expense	-							31.14				
December	0.5							0.5				
Deprec Exp.on Dec Addition/Retirement	-							**16**		**16**		
Plant In Service at 12/31/09	**19,303,754**	**2,009,542**	**31,762**	**604,451**	**398,628**	**469,590**	**113,302**	**1,340,187**		**4,967,462**	**24,271,216**	**24,271,216**
Accumulated provision for Depreciation at 12/31/09	**6,724,974**	**964,175**	**5,905**	**79,453**	**43,891**	**36,418**	**4,537**	**32,585**		**1,166,965**	**7,891,939**	**7,891,939**
Net Plant NBV @ 12/31/09	**12,578,780**	**1,045,367**	**25,858**	**524,999**	**354,737**	**433,172**	**108,765**	**1,307,601**		**3,800,497**	**16,379,278**	**16,379,277**
Depreciation expense 2009	**650,426**	**62,698**	**991**	**18,859**	**12,437**	**14,651**	**3,535**	**32,585**		**145,756**	**796,182**	**796,182**
YEAR 2010	**Pre - 97 (PTF)**	**Post - 96 (PTF)**									**Total Pre 97 and Post 96 (PTF)**	**FERC FORM 1 Footnote**
		Pre -2004	**2004 Additions**	**2005 Additions**	**2006 Additions**	**2007 Additions**	**2008 Additions**	**2009 Additions**	**2010 Additions**	**Total Post - 96**		
Plant In Service at 12/31/09	**19,303,754**	**2,009,542**	**31,762**	**604,451**	**398,628**	**469,590**	**113,302**	**1,340,187**	**-**	**4,967,462**	**24,271,216**	**24,271,216**
Accumulated provision for Depreciation at 12/31/09	**6,724,974**	**964,175**	**5,905**	**79,453**	**43,891**	**36,418**	**4,537**	**32,585**	**-**	**1,166,965**	**7,891,939**	**7,891,939**
Net Plant NBV @ 12/31/09	**12,578,780**	**1,045,367**	**25,858**	**524,999**	**354,737**	**433,172**	**108,765**	**1,307,601**	**-**	**3,800,497**	**16,379,278**	**16,379,277**
2010												
Additions												
January												
February												
March												
April												
May												
Retirements												
April	(227,913)											
May	(113,956)											
Removal												
April	(89,993)											
May	(44,997)											
Adjustment												
Monthly Depreciation Expense												
Depreciable Balance @ 12/31/09	**19,303,754**	**2,009,542**	**31,762**	**604,451**	**398,628**	**469,590**	**113,302**	**1,340,187**		**4,967,462**		
Monthly Depreciation Rate = .0312 /12	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026				
Monthly Depreciation Expense	50,190	5,225	83	1,572	1,036	1,221	295	3,484		**12,915**		
Jan - May	5	5	5	5	5	5	5	5				
Depreciation Expense on 2009 Balance	**250,949**	**26,124**	**413**	**7,858**	**5,182**	**6,105**	**1,473**	**17,422**		**64,577**		
Add:												
Deprec Exp.on Jan Addition/Retirement												
January Additions/Retirements									-			
Monthly Depreciation Rate = .0312 /12	0.0026								0.0026			
Monthly Depreciation Expense	-								-			
Jan - May	4.5								4.5			
Deprec Exp.on Jan Addition/Retirement	-								**0**	**-**		
Add:												
Feb Additions/Retirements	-								-			
Monthly Depreciation Rate = .0312 /12	0.0026								0.0026			
Monthly Depreciation Expense	-								-			
Feb - May	3.5								3.5			
Deprec Exp.on Feb Addition/Retirement	-								-	-		
Add:												
March Additions/Retirements									-			
Monthly Depreciation Rate = .0312 /12	0.0026								0.0026			
Monthly Depreciation Expense	-								-			
March - May	2.5								9.5			
Deprec Exp.on March Addition/Retirement	-								-	-		
Add:												
April Additions/Retirements	(227,913)								-			
Monthly Depreciation Rate = .0312 /12	0.0026								0.0026			
Monthly Depreciation Expense	(593)								-			
April - May	1.5								8.5			
Deprec Exp.on April Addition/Retirement	(889)								-	-		
Add:												
May Additions/Retirements	(113,956)								-			
Monthly Depreciation Rate = .0312 /12	0.0026								0.0026			
Monthly Depreciation Expense	(296)								-			
May - May	0.5								7.5			
Deprec Exp.on May Addition/Retirement	(148)									-		
Add:												
June Additions/Retirements	-							-				
Monthly Depreciation Rate = .0312 /12	0.0026							0.0026				
Monthly Depreciation Expense	-							-				
June - December	6.5							6.5				
Deprec Exp.on Oct. Addition/Retirement	-							-		-		
Add:												
July Additions/Retirements	-							-				
Monthly Depreciation Rate = .0312 /12	0.0026							0.0026				
Monthly Depreciation Expense	-							-				
July - December	5.5							5.5				
Deprec Exp.on Oct. Addition/Retirement	-							-		-		
Add:												
August Additions/Retirements	-							-				
Monthly Depreciation Rate = .0312 /12	0.0026							0.0026				
Monthly Depreciation Expense	-							-				
August - December	4.5							4.5				
Deprec Exp.on Oct. Addition/Retirement	-							-		-		

Add:												
Sept Additions/Retirements	-							-				
Monthly Depreciation Rate = .0312 /12	0.0026							0.0026				
Monthly Depreciation Expense	-							-				
Sept - December	3.5							3.5				
Deprec Exp.on Oct. Addition/Retirement	-							-		-		
Add:												
Oct Additions/Retirements	(113,956)							-				
Monthly Depreciation Rate = .0312 /12	0.0026							0.0026				
Monthly Depreciation Expense	(296)							-				
Oct - December	2.5							2.5				
Deprec Exp.on Oct. Addition/Retirement	(741)							-		-		
Add:												
Nov Additions/Retirements	-							-				
Monthly Depreciation Rate = .0312 /12	0.0026							0.0026				
Monthly Depreciation Expense	-							-				
Nov - December	1.5							1.5				
Deprec Exp.on Oct. Addition/Retirement	-							-		-		
Add:												
Dec Additions/Retirements	-							-				
Monthly Depreciation Rate = .0312 /12	0.0026							0.0026				
Monthly Depreciation Expense	-							-				
December	0.5							0.5				
Deprec Exp.on Dec Addition/Retirement	-							-	-	-		
Plant In Service at 5/31/10	**18,961,885**	**2,009,542**	**31,762**	**604,451**	**398,628**	**469,590**	**113,302**	**1,340,187**	**856,995**	**5,824,457**	**24,786,342**	**24,786,342**
Accumulated provision for Depreciation at 5/31/10	**6,497,286**	**990,299**	**6,318**	**87,311**	**49,074**	**42,523**	**6,010**	**50,008**	**8,211**	**1,239,753**	**7,737,039**	**7,737,039**
Net Plant NBV @ 5/31/10	**12,464,599**	**1,019,243**	**25,445**	**517,141**	**349,555**	**427,067**	**107,292**	**1,290,179**	**848,783**	**4,584,704**	**17,049,303**	**17,049,303**
Depreciation expense Jan - May 2010	**249,171**	**26,124**	**413**	**7,858**	**5,182**	**6,105**	**1,473**	**17,422**	**8,210**	**72,787**	**321,958**	**321,958**
Monthly Depreciation Expense												
Depreciable Balance @ 5/31/10	**18,961,885**	**2,009,542**	**31,762**	**604,451**	**398,628**	**469,590**	**113,302**	**1,340,187**	**856,995**	**5,824,457**		
Monthly Depreciation Rate = .0312 /12	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026			
Monthly Depreciation Expense	49,301	5,225	83	1,572	1,036	1,221	295	3,484	2,228	**12,915**		
June - Dec	7	7	7	7	7	7	7	7	7			
June thru Dec Depreciation Expense on 5/31/2010 Ba	**345,106**	**36,574**	**578**	**11,001**	**7,255**	**8,547**	**2,062**	**24,391**	**15,597**	**90,408**		
2010												
Additions												
November												
Retirements												
September	(115,849)											
Add:												
June Additions/Retirements	-											
Monthly Depreciation Rate = .0312 /12	0.0026											
Monthly Depreciation Expense	-											
June - December	6.5											
Deprec Exp.on Oct. Addition/Retirement	-											
Add:												
July Additions/Retirements	-											
Monthly Depreciation Rate = .0312 /12	0.0026											
Monthly Depreciation Expense	-											
July - December	5.5											
Deprec Exp.on Oct. Addition/Retirement	-											
Add:												
August Additions/Retirements	-											
Monthly Depreciation Rate = .0312 /12	0.0026											
Monthly Depreciation Expense	-											
August - December	4.5											
Deprec Exp.on Oct. Addition/Retirement	-											
Add:												
Sept Additions/Retirements	(115,849)											
Monthly Depreciation Rate = .0312 /12	0.0026											
Monthly Depreciation Expense	(301)											
Sept - December	3.5											
Deprec Exp.on Oct. Addition/Retirement	(1,054)											
Add:												
Oct Additions/Retirements	6											
Monthly Depreciation Rate = .0312 /12	0.0026											
Monthly Depreciation Expense	0											
Oct - December	2.5											
Deprec Exp.on Oct. Addition/Retirement	0											
Add:												
Nov Additions/Retirements	-								864,873			
Monthly Depreciation Rate = .0312 /12	0.0026								0.0026			
Monthly Depreciation Expense	-								2,248.67			
Nov - December	1.5								1.5			
Deprec Exp.on Oct. Addition/Retirement	-								**3,373**	**Note - depr incorrectly excluded from pooled transmission facilities. Correction will be made in 2011.**		
Add:												
Dec Additions/Retirements	-											
Monthly Depreciation Rate = .0312 /12	0.0026											
Monthly Depreciation Expense	-											
December	0.5											
Deprec Exp.on Dec Addition/Retirement	-											Reported to FERC
Plant In Service at 12/31/10	**18,846,036**	**2,009,542**	**31,762**	**604,451**	**398,628**	**469,590**	**113,302**	**1,340,187**	**1,721,868**	**6,689,330**	**25,535,366**	**25,535,370**
Accumulated provision for Depreciation at 12/31/10	**6,726,543**	**1,026,873**	**6,896**	**98,312**	**56,329**	**51,069**	**8,072**	**74,399**	**27,182**	**1,349,132**	**8,075,674**	**8,072,477**
Net Plant NBV @ 12/31/2010	**12,119,493**	**982,669**	**24,867**	**506,140**	**342,300**	**418,520**	**105,230**	**1,265,787**	**1,694,686**	**5,340,199**	**17,459,692**	**17,462,893**
Depreciation expense Jun - Dec 2010	**345,106**	**36,574**	**578**	**11,001**	**7,255**	**8,547**	**2,062**	**24,391**	**18,970**	**109,378**	**454,484**	**451,288**

Change in Plant in Service
Year 2010

		PTF Only				Non PTF			LNS				
Accounting Month		**Additions**	**Retirements**	**Removal**	**Total PTF**	**NPTF**	**GSU-C**	**FUT**	**Sum of PTF, NPTF GSU-C,FUT**	**GSU**	**SS**	**Project 52**	**Grand 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 Reliabilty 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

		PTF Only				Non PTF			LNS				
		Additions	**Retirements**	**Removal**	**Total PTF**	**NPTF**	**GSU-C**	**FUT**	**PTF, NPTF GSU-C,FUT**	**GSU**	**SS**	**Project 52**	**Grand Total**
June	CIAC				-				-			(17,052,629)	(17,052,628.63)
September	Retire Sequence Event Recorder - EY 5652		(53,746.39)		(53,746.39)				(53,746.39)				(53,746.39)
September	Retire Fault Recorder / Oscilligraph - EY 3501		(100,718.57)		(100,718.57)				(100,718.57)				(100,718.57)
October	Adj- Contractor / Consultant invoice - MEPPI				-				-			(2,170,306)	(2,170,306.00)
November	APP Engineering Model Recorder	390,061.28			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				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	(154,464.96)	-	710,407.97	-	-	-	710,407.97	-	130,020.43	(18,471,792.84)	(17,631,364.45)

Florida Power & Light Company - New England Division
Statement AE
Summary
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Accumulated Depreciation and Amortization
Summary

ASSUMES: Tools and Test 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.

Line No.																
1																
2																
3																
4	**Account 353 Balances, Including Test Equipment**															
5																
6	As of December 31, 2002	100%	88.22889%													
7																
8	Plant in Service	$ 53,069,453	46,822,590													
9																
10	Accumulated Depreciation	13,891,620	12,256,422							AT						
11	Net Plant	$ 39,177,833	$ 34,566,168							88.22889%						
12							(c)			(f)	(g)		(h)		(i)	
13		100%	88.22889%		(a)	(b)	(a + b)	(d)	(e)	(c+d+e)						
14	As of December 31, 2003 (REVISED)						PTF			Total						
15					PTF	NPTF	NPTF	GSU-C	FUT	LNS	GSU	GSU-Diff	SS		Total	
16	Plant in Service Excluding Land	$ 53,135,792	46,881,120		24,005,775	1,114,791	25,120,566	2,711,593	362,952	28,195,111	16,970,656		1,715,353		46,881,120	
17																
18	Accumulated Depreciation	15,547,473	13,717,363		7,024,063	326,187	7,350,249	793,409	106,199	8,249,858	4,965,595		501,910		13,717,363	
19	Net Plant	$ 37,588,319	$ 33,163,757		$ 16,981,712	$ 788,604	$ 17,770,317	$ 1,918,184	$ 256,753	19,945,253	$ 12,005,061		$ 1,213,443		$ 33,163,757	
20																
21										88.22889%						
22	As of May 31, 2004 estimated/actual	100%	88.22889%				PTF			Total						LNS + SS +
23					PTF	NPTF	NPTF	GSU-C	FUT	LNS	GSU	GSU-Diff	SS		Total	GSU-Diff + Prj 52
24	Plant in Service Excluding Land	$ 53,235,742	46,969,305		24,037,538	1,115,850	25,153,388	2,712,652	363,481	28,229,521	16,966,982	21,427	1,751,376		46,969,306	30,002,324
25																
26	Accumulated Depreciation	16,239,408	14,327,849		7,336,509	340,691	7,677,201	828,672	110,924	8,616,797	5,185,016	1,407	524,631		14,327,852	9,142,835
27	Net Plant	$ 36,996,335	$ 32,641,456		$ 16,701,029	$ 775,159	$ 17,476,187	$ 1,883,980	$ 252,557	$ 19,612,724	$ 11,781,966	$ 20,020	$ 1,226,745		32,641,455	20,859,489
28				100%	18,929,206	878,577	$ 19,807,783	2,135,332	286,252	$ 22,229,368	13,353,864	22,691	1,390,411		36,996,334	23,642,470
29																
30	As of December 31, 2004															
31																
32	Plant in Service	$ 53,235,742	$ 46,969,305		$ 24,037,538	$ 1,115,850	$ 25,153,388	$ 2,712,652	$ 363,481	$ 28,229,521	$ 16,966,982	$ 21,427	$ 1,751,376		$ 46,969,305	$ 30,002,324
33	Accumulated Depreciation @ 5/31/04	16,239,408	14,327,849		7,336,509	340,691	7,677,201	828,672	110,924	8,616,797	5,185,016	1,407	524,631		14,327,849	9,142,835
34	Accumulated Depreciation June - December 2004	968,891	854,840		437,483	20,308	457,792	49,370	6,615	513,777	308,799	390	31,875		854,841	546,042
35	Net Plant	$ 36,027,444	$ 31,786,615		$ 16,263,545	$ 754,850	$ 17,018,396	$ 1,834,610	$ 245,942	$ 19,098,947	$ 11,473,167	$ 19,630	$ 1,194,870		$ 31,786,614	20,313,446
36																
37										88.22889%						
54																
55	**As of December 31, 2005**	100%	88.22889%				PTF			Total						LNS + SS +
56		MEMO ONLY			PTF	NPTF	NPTF	GSU-C	FUT	LNS	GSU	GSU-Diff	SS		Total	GSU-Diff + Prj 52
57	**Plant in Service**	$ 53,466,303	$ 47,172,726		$ 24,240,959	$ 1,115,850	$ 25,356,809	$ 2,712,652	$ 363,481	$ 28,432,942	$ 16,966,982	$ 21,427	$ 1,751,376		$ 47,172,728	$ 30,205,745
58																
59	**Accumulated Depreciation**	18,416,524	16,248,695		8,124,527	395,814	8,520,341	962,677	128,880	9,611,898	6,023,185	2,466	611,149		16,248,698	10,225,513
60	**Net Plant**	$ 35,049,779	$ 30,924,031		$ 16,116,433	$ 720,036	$ 16,836,468	$ 1,749,975	$ 234,601	$ 18,821,044	$ 10,943,797	$ 18,961	$ 1,140,227		$ 30,924,029	19,980,232
66																
67										88.22889%						
84																
85	**As of December 31, 2006**	100%	88.22889%				PTF			Total						LNS + SS +
86		MEMO ONLY			PTF	NPTF	NPTF	GSU-C	FUT	LNS	GSU	GSU-Diff	SS		Total	GSU-Diff + Prj 52
87	**Plant in Service**	$ 53,762,737	$ 47,434,266		$ 24,502,499	$ 1,115,850	$ 25,618,349	$ 2,712,652	$ 363,481	$ 28,694,482	$ 16,966,982	$ 21,427	$ 1,751,376		$ 47,434,268	$ 30,467,285
88																
89	**Accumulated Depreciation**	19,934,185	17,587,710		8,748,068	430,629	9,178,697	1,047,312	140,220	10,366,229	6,552,555	3,134	665,792		17,587,711	11,035,156
90	**Net Plant**	$ 33,828,552	$ 29,846,556		$ 15,754,431	$ 685,221	$ 16,439,652	$ 1,665,340	$ 223,261	$ 18,328,253	$ 10,414,427	$ 18,293	$ 1,085,584		$ 29,846,557	19,432,129
91																
97										88.22889%						
114			88.22889%				PTF			Total						LNS + SS +
115	**As of December 31, 2007**	100%			PTF	NPTF	NPTF	GSU-C	FUT	LNS	GSU		SS		Total	GSU-Diff + Prj 52
116		MEMO ONLY														
117	**Plant in Service**	$ 54,166,367	$ 47,790,385		$ 24,838,002	$ 1,121,069	$ 25,959,071	$ 2,728,049	$ 363,481	$ 29,050,601	$ 16,966,982	$ 21,427	$ 1,751,376	$ -	$ 47,790,386	$ 30,823,404
118																
119	**Accumulated Depreciation**	21,461,516	18,935,257		9,379,960	465,490	9,845,450	1,132,086	151,561	11,129,097	7,081,925	3,803	720,435	-	18,935,260	11,853,335
120	**Net Plant**	$ 32,704,851	$ 28,855,127		$ 15,458,042	$ 655,579	$ 16,113,621	$ 1,595,963	$ 211,920	$ 17,921,504	$ 9,885,057	$ 17,624	$ 1,030,941	$ -	$ 28,855,126	18,970,069
121																
129										88.22889%						
146			88.22889%				PTF			Total						LNS + SS +
147	**As of December 31, 2008**	100%			PTF	NPTF	NPTF	GSU-C	FUT	LNS	GSU	GSU-Diff	SS		Total	GSU-Diff + Prj 52
148		MEMO ONLY														
149	**Plant in Service** (per ABB Study - adjusted)	$ 54,329,325	$ 47,934,160		$ 24,951,304	$ 1,124,730	$ 26,076,033	$ 2,730,504.75	365,917	$ 29,172,455	$ 16,966,982	$ 25,081	$ 1,769,644		$ 47,934,162	30,967,179
150																
151	**Accumulated Depreciation**	$ 23,152,869	20,427,520		10,155,908	500,492	10,656,400	1,217,218	162,918	12,036,536	7,611,295	4,495	775,197		$ 20,427,522	12,816,227
152	**Net Plant**	$ 31,176,456	$ 27,506,641		$ 14,795,396	$ 624,238	$ 15,419,634	$ 1,513,286	$ 202,999	$ 17,135,919	$ 9,355,687	$ 20,586	$ 994,447		$ 27,506,640	18,150,952
153																
160																
161										88.22889%						
162			88.22889%				PTF			Total						LNS + SS +
163	**Depreciation Expense for 2009**	MEMO ONLY			PTF	NPTF	NPTF	GSU-C	FUT	LNS	GSU	GSU-Diff	SS	Project 52	Total	GSU-Diff + Prj 52
164																

165	January, 2009		$ 140,833	124,256	65,431	2,932	68,362	7,122	951	76,436	44,114	65	4,601	0	125,216	81,102
166	February 2009		$ 140,836	124,258	65,988	2,939	68,927	7,144	951	77,023	44,114	65	4,601	0	125,803	81,689
167	March, 2009		$ 140,839	124,260	66,417	2,938	69,355	7,143	951	77,449	44,114	64	4,595	0	126,223	82,108
168	April, 2009		$ 140,844	124,265	66,934	2,937	69,871	7,143	950	77,964	44,114	63	4,590	0	126,732	82,617
169	May, 2009		$ 140,848	124,269	67,383	2,937	70,321	7,143	950	78,414	44,114	63	4,591	0	127,182	83,068
170	June, 2009		$ 140,873	124,291	67,816	2,937	70,753	7,143	950	78,846	44,114	63	4,591	0	127,614	83,500
171	July, 2009		$ 140,897	124,312	68,017	2,937	70,954	7,143	950	79,047	44,114	63	4,591	0	127,815	83,701
172	Aug, 2009		$ 140,897	124,312	68,154	2,937	71,091	7,143	950	79,184	44,114	63	4,591	0	127,952	83,838
173	Sept, 2009		$ 140,897	124,312	68,213	2,937	71,151	7,143	950	79,243	44,114	63	4,591	0	128,012	83,897
174	Oct, 2009		$ 141,077	124,470	65,668	2,571	68,238	7,046	871	76,155	44,114	63	4,493	58,942	183,768	139,654
175	Nov, 2009		$ 141,256	124,629	63,073	2,204	65,277	6,949	791	73,017	44,114	63	4,396	119,353	240,943	196,829
176	Dec, 2009		$ 141,256	124,629	63,090	2,204	65,294	6,949	791	73,034	44,114	63	4,396	120,822	242,429	198,315
177	Total Jan - December 2009		1,691,353	1,492,262	796,182	33,413	829,595	85,210	11,007	925,812	529,370	763	54,627	299,116	1,809,688	1,280,318
178																
179				88.22889%			PTF			Total	Memo Only					LNS + SS +
180	**As of December 31, 2009**		100%		PTF	NPTF	NPTF	GSU-C	FUT	LNS	GSU	GSU-Diff	SS	Project 52	Total	GSU-Diff + Prj 52
181			MEMO ONLY													
182	**Plant in Service** **(per ABB Study - adjusted)**		$ 58,733,366	**$ 51,819,797**	**$ 24,271,216**	**$ 847,708**	**$ 25,118,924**	**$ 2,672,818**	**$ 304,353**	**$ 28,096,094**	**$ 16,966,982**	**$ 24,301**	**$ 1,690,608**	**$ 46,469,812**	**$ 46,777,986**	**$ 76,280,816**
183																
184	**Accumulated Depreciation**		$ 29,176,596	**25,742,187**	**7,891,939**	**100,402**	**7,992,341**	**1,187,793**	**79,756**	**9,259,891**	**8,140,665**	**4,479**	**710,655**	**299,116**	**$ 18,115,689**	**10,274,141**
185	**Net Plant**		$ 29,556,770	**$ 26,077,610**	**$ 16,379,277**	**$ 747,305**	**$ 17,126,582**	**$ 1,485,024**	**$ 224,597**	**$ 18,836,203**	**$ 8,826,318**	**$ 19,823**	**$ 979,953**	**$ 46,170,696**	**$ 28,662,297**	**66,006,675**
186																
187	2009 Changes	Additions	1,548,506	1,366,230	1,343,187	5,825	1,349,012	17,218	-	1,366,230	-	-	-	46,469,812	1,366,230	47,836,042
188		Removal	(1,476,839)	(1,302,999)	(1,039,877)	(150,655)	(1,190,532)	(39,730)	(32,604)	(1,262,866)	-	-	(40,132.95)	-	(1,302,999)	(1,302,999)
189		Retirements	(2,855,534)	(2,519,406)	(2,020,274)	(282,848)	(2,303,122)	(74,905)	(61,564)	(2,439,591)	-	(779)	(79,036)	-	(2,519,406)	(2,519,406)
190		Depreciation	1,691,353	1,492,262	796,182	33,413	829,595	85,210	11,007	925,812	529,370	763	54,627	299,116	1,510,572	1,280,318
191																
192																
193																
194										88.22889%						
195				88.22889%			PTF			Total						LNS + SS +
196	**Depreciation Expense for 2010**		MEMO ONLY		PTF	NPTF	NPTF	GSU-C	FUT	LNS	GSU	GSU-Diff	SS	Project 52	Total	GSU-Diff + Prj 52
197																
198	January, 2010		$ 140,833	124,256	63,379	2,204	65,583	6,949	791	73,324	44,114	63	4,396	120,822	242,718	198,604
199	February 2010		$ 140,836	124,258	65,488	2,204	67,692	6,949	791	75,433	44,114	63	4,396	120,822	244,827	200,713
200	March, 2010		$ 140,839	124,260	65,014	2,204	67,218	6,949	791	74,959	44,114	63	4,396	123,539	247,071	202,957
201	April, 2010		$ 140,844	124,265	63,603	2,204	65,807	6,949	791	73,548	44,114	63	4,396	124,251	246,372	202,258
202	May, 2010		$ 140,848	124,269	64,474	2,204	66,678	6,949	791	74,418	44,114	63	4,396	122,252	245,244	201,129
203	Total Jan - May 2010		704,199	621,307	321,958	11,020	332,979	34,747	3,957	371,682	220,571	316	21,978	611,686	1,226,232	1,005,662
204																
205				88.22889%			PTF			Total	Memo Only					LNS + SS +
206	**As of May 31, 2010**		100%		PTF	NPTF	NPTF	GSU-C	FUT	LNS	GSU	GSU-Diff	SS	Project 52	Total	GSU-Diff + Prj 52
207			MEMO ONLY													
208	**Plant in Service** **(per ABB Study - adjusted)**		$ 60,092,178	**$ 53,018,662**	**$ 24,786,342**	**$ 847,708**	**$ 25,634,050**	**$ 2,672,818**	**$ 304,353**	**$ 28,611,220**	**$ 16,966,982**	**$ 24,301**	**$ 1,690,608**	**$ 47,022,772**	**$ 47,293,112**	**$ 77,348,901**
209																
210	**Accumulated Depreciation**		$ 30,421,273	**26,840,352**	**7,737,039**	**111,423**	**7,848,462**	**1,222,540**	**83,712**	**9,154,714**	**8,361,236**	**4,795**	**732,633**	**910,802**	**$ 18,253,377**	**10,802,944**
211	**Net Plant**		$ 29,670,904	**$ 26,178,310**	**$ 17,049,303**	**$ 736,285**	**$ 17,785,588**	**$ 1,450,278**	**$ 220,640**	**$ 19,456,506**	**$ 8,605,747**	**$ 19,507**	**$ 957,975**	**$ 46,111,969**	**$ 29,039,735**	**66,545,957**
212																
213	2010 Changes	Additions	971,332	856,995	856,995	-	856,995	-	-	856,995	-	-	-	552,959	856,995	1,409,955
214		Removal	(152,999)	(134,989)	(134,989)	-	(134,989)	-	-	(134,989)	-	-	-	-	(134,989)	(134,989)
215		Retirements	(387,480)	(341,869)	(341,869)	-	(341,869)	-	-	(341,869)	-	-	-	-	(341,869)	(341,869)
216		Depreciation	704,199	621,307	321,958	11,020	332,979	34,747	3,957	371,682	220,571	316	21,978	611,686	614,546	1,005,662
217																
218				88.22889%			PTF			Total						LNS + SS +
219	**Depreciation Expense for 2010**		MEMO ONLY		PTF	NPTF	NPTF	GSU-C	FUT	LNS	GSU	GSU-Diff	SS	Project 52	Total	GSU-Diff + Prj 52
220																
221	June, 2010		$ 174,726	154,159	64,470	2,215	66,685	6,985	795	74,465		87	4,294	75,314	154,159	154,159
222	July 2010		$ 174,726	154,159	64,470	2,215	66,685	6,985	795	74,465		87	4,294	75,314	154,159	154,159
223	August, 2010		$ 174,726	154,159	64,470	2,215	66,685	6,985	795	74,465		87	4,294	75,314	154,159	154,159
224	September, 2010		$ 174,726	154,159	64,470	2,215	66,685	6,985	795	74,465		87	4,294	75,314	154,159	154,159
225	October, 2010		$ 174,726	154,159	64,470	2,215	66,685	6,985	795	74,465		87	4,294	75,314	154,159	154,159
226	November, 2010		$ 174,726	154,159	64,470	2,215	66,685	6,985	795	74,465		87	4,294	75,314	154,159	154,159
227	December, 2010		$ 174,726	154,159	64,470	2,215	66,685	6,985	795	74,465		87	4,294	75,314	154,159	154,159
228	Total Jun-Dec 2010		1,223,085	1,079,114	451,288	15,507	466,795	48,893	5,567	521,255	0	606	30,057	527,196	1,079,114	1,079,114
229																
230				88.22889%			PTF			Total	Memo Only					LNS + SS +
231	**As of December 31, 2010**		100%		PTF	NPTF	NPTF	GSU-C	FUT	LNS	GSU	GSU-Diff	SS	Project 52	Total	GSU-Diff + Prj 52
232			MEMO ONLY													
233	**Plant in Service** **(per ABB Study - adjusted)**		$ 61,394,879	**$ 54,168,020**	**$ 25,496,750**	**$ 847,708**	**$ 26,344,458**	**$ 2,672,818**	**$ 304,353**	**$ 29,321,628**	**$ 16,966,982**	**$ 24,301**	**$ 1,820,628**	**$ 28,550,979**	**$ 48,133,540**	**$ 59,717,537**
234																
235	**Accumulated Depreciation**		$ 31,819,431	**28,073,931**	**8,033,862**	**126,930**	**8,160,791**	**1,271,433**	**89,280**	**9,521,504**	**8,361,236**	**5,401**	**762,690**	**2,429,491**	**$ 18,650,831**	**12,719,086**
236	**Net Plant**		$ 29,575,448	**$ 26,094,089**	**$ 17,462,888**	**$ 720,778**	**$ 18,183,666**	**$ 1,401,385**	**$ 215,073**	**$ 19,800,124**	**$ 8,605,747**	**$ 18,900**	**$ 1,057,938**	**$ 26,121,488**	**$ 29,482,710**	**46,998,451**
237																
238	July- Dec 2010 Chang	Additions	1,127,628	994,893	864,873	-	864,873	-	-	864,873	-	-	130,020.43	(1,419,164)	994,893	(424,271)
239		CIAC	-	-						-				(17,052,629)	-	(17,052,629)
240		Removal	-	-		-	-	-	-	-	-	-	-		-	-
241		Adjustment to acc. Deprec	-											991,493		
242		Retirements	(175,073)	(154,465)	(154,465)	-	(154,465)	-	-	(154,465)	-	-	-	-	(154,465)	(154,465)
243		Depreciation	1,223,085	1,079,114	451,288	15,507	466,795	48,893	5,567	521,255	0	606	30,057	527,196	551,918	1,079,114

Plant Data Support for FPL-NED's / NHT's Seabrook Reliabiltiy Upgrade 5-Breaker Project

Facilities Description -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
	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% Newtington / 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

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	7.3090%
	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%

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%
Total DAF+RNS+LNS		**46,469,812**	100.0000%	**60,129,998**	100.0000%

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 determinermination under Schedule 12C.

Supporting information for calculatoin of FPL-NED's Annual Transmission Revenue Requirements

Derivation of Depreciation Expense

Depreciation Expense Not Subject to Pending TCA Review	**(a)** **Percentage**	**(b)** **Source**		**(c)** **Pool-Supported PTF**	**Source**
Total PTF Related	100.43%	NA	$	773,118	Form 1
Pre-97 PTF	76.87%	NA		594,277	Plant Data Support 1 & 1A
Post-96 PTF	23.56%	NA		182,165	Plant Data Support 1 & 1A

Depreciation Expense	**Percentage**	**Source**		**Reliabilty Upgrade (See Note)**	**Source**
Total Pending a TCA Review (Reliability Upgrade Project)	100.00%	NA	$	1,139,010	Form 1
Pool-Supported PTF (pending TCA approval)	45.95%	Plant Data Support 4		523,385	(a) x (c)
Costs not requested to be Pool-Supported	54.05%	Plant Data Support 4		615,625	(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	$	8,075,674	Form 1 (adjusted)
Pre-97 PTF	83.29%	NA		6,726,543	Plant Data Support 1A
Post-96 PTF	16.71%	NA		1,349,132	Plant Data Support 1A

Accumulated Depreciation Reserve	**Percentage**	**Source**		**Reliabilty Upgrade (See Note)**	**Source**
Total Pending a TCA Review (Reliability Upgrade Project)	100.00%	NA	$	2,429,492	Form 1
Pool-Supported PTF (pending TCA approval)	45.95%	Plant Data Support 4		1,116,373	(a) x (c)
Costs not requested to be Pool-Supported	54.05%	Plant Data Support 4		1,313,119	(a) x (c)

Derivation of Accumulated Deferred Taxes

Accumulated Deferred Taxes Not Subject to Pending TCA Review	**(a)** **Percentage**	**(b)** **Source**		**(c)** **Pool-Supported PTF**	**Source**
Total PTF Related	100.00%	NA	$	3,998,468	see below
Pre-97 PTF	34.84%	WS 5		1,393,240	(a) x (c)
Post-96 PTF	65.16%	WS 5		2,605,228	(a) x (c)

Accumulated Deferred Taxes	**Percentage**	**Source**		**Reliabilty Upgrade (See Note)**	**Source**
Total Pending a TCA Review (Reliability Upgrade Project)	100.00%	NA	$	4,470,669	see below
Pool-Supported PTF (pending TCA approval)	45.95%	Plant Data Support 4		2,054,312	(a) x (c)
Costs not requested to be Pool-Supported	54.05%	Plant Data Support 4		2,416,357	(a) x (c)

Total Accumulated Deferred Taxes from 2010 Form 1				**$**	**12,578,053**	
Less amount attributed to CIAC received from Local Customer				**$**	**(3,227,154)**	
				$	**9,350,899**	
		Dollars	**Percenages**			
Gross PTF Plant In Service	$	25,535,370	42.7603%			
Gross Pre-'97 PTF Plant In Service		18,846,036	31.5586%		2,951,016	
Gross Post-'96 PTF Plant In Service		6,689,330	11.2016%		1,047,452	3,998,468
Gross Non-PTF Plant In Service		3,824,874	6.4049%		598,920	
Gross Reliability Upgrade Plant In-Service		28,550,979	47.8100%		4,470,669	4,470,669
Gross Amounts Excluded from LNS Tariff		1,806,314	3.0248%		282,843	
Total Gross Plant In Service	$	59,717,533	100.0000%	$	9,350,899	

Note: The Reliabilty Upgrade pending TCA review and approval is related to a project implemented under the approved Proposed Plan Application FPLC-08-T01.
The amount of Depreciation Expense, Accumulated Deferred Taxes reflected in PTF revenue requirements
is equal to the portion of total project costs NHT anticipates will be eligible for regional cost recovery, and is included
herein subject to adjustment in accordance with a final Transmission Cost Allocation (TCA) determination.

Seabrook Substation

	FPL-NED			
	12/31/2009 per D&T	5/31/2010 Transfer	12/31/2010 NHT	
Plant in Service				
PTF	24,271,216	24,786,342	25,535,370	0.427603
NPTF	3,824,878	3,824,878	3,824,874	0.064049
Reliability Upgrade	46,469,812	47,022,772	28,550,979	0.478100
Amounts Excluded	1,714,909	1,714,909	1,806,314	0.030248
Total	76,280,815	77,348,901	59,717,537	1.000000
Accum Prov for Deprec				
PTF	7,891,939	7,737,039	8,072,477	
NPTF	1,367,952	1,417,675	1,449,026	
Reliability Upgrade	299,116	910,802	2,429,492	
Amounts Excluded	715,134	737,427	768,090	
Total	10,274,141	10,802,943	12,719,085	
Net Plant				
PTF	16,379,277	17,049,303	17,462,893	
NPTF	2,456,926	2,407,203	2,375,848	
Reliability Upgrade	46,170,696	46,111,970	26,121,487	
Amounts Excluded	999,775	977,482	1,038,224	
Total	66,006,674	66,545,958	46,998,452	
	TRUE	TRUE	TRUE	
Effective rate on ugrade	17.64051%	17.64050%	31.40642%	

	CIAC Adjustment	Year 2009	Year 2010
CIAC	17,052,628	17,052,628	17,052,628
New Hampshire Depre.	1,055,131	213,158	841,974
New Hampshire Def. Tax	89,686	18,118	71,568
Bonus Depreciation 09	8,526,314	8,526,314	8,526,314
Federal Depreciation	527,566	106,579	420,987
Total Federal Depr.	9,053,880	8,632,893	420,987
Federal net of state tax Ben	8,964,194	8,614,775	349,419
Federal Deferred Tax	3,137,468	3,015,171	122,297
Deferred Tax related to CIAC	3,227,154	3,033,289	193,864

Allocation Percentages based on Net Plant

	Dec. 31, 2009		30-May-10		31-Dec-10		
	16,379,277	A	17,049,303	A	17,462,893	A	
	2,456,926	B	2,407,203	B	2,375,848	B	
	46,170,696		46,111,970		26,121,487		0.3140642
	999,775	C	977,482	C	1,038,224	C	
	66,006,674		66,545,958		46,998,452		
	(46,170,696)		(46,111,970)		(26,121,487)		
	19,835,978	D	20,433,988	D	20,876,965	D	
PTF	0.82574	A/D	0.83436	A/D	0.83647	A/D	
NPTF	0.12386	B/D	0.11780	B/D	0.11380	B/D	
Amounts Excluded	0.05040	C/D	0.04784	C/D	0.04973	C/D	

Deferred Tax Balance	**12/31/2009**	**5/31/2010**	**12/31/2010**	
PTF	2,608,294	3,596,531	3,666,426	
NPTF	391,249	507,797	498,822	
Reliability Upgrade	8,144,746	4,907,228	4,976,670	
CIAC		3,227,154	3,227,154	
Amounts Excluded	159,208	206,199	217,981	
Total	11,303,497	12,444,909	12,587,052	Ferc form: $12,587,053- off by $1 due to rounding
Less Relib Upgrade	(8,144,746)	(4,907,130)	(4,976,670)	
CIAC		(3,227,252)	(3,227,154)	
Allocated on net plant	**3,158,751**	**4,310,527**	**4,383,228**	

Consolidation of FPL and NHT Form 1 Data for 2010 Pertaining to NHT

Assets	123.46 - 123.48, 450.1 - 450.2	NHT Form 1
ELELCTRIC UTILITY PLAN:		
Transmission Plant in service	$ 77,348,901	$ 59,717,537
Electric Plant In Service Subcategory:		
Pool Transmission Facilities (PTF)	Not Provided	$ 25,535,370
Non-Pool Transmission Facilities (NPTF)	Not Provided	3,824,874
Reliability Upgrade (Pool Supported PTF/NPTF TBD)	Not Provided	28,550,979
Amounts excluded under the LNS Tariff	Not Provided	1,806,314
Total Transmission Plant In-Service	$ 77,348,901	$ 59,717,537
Construction work in progress	2,387,986	
Accumulated Provision for Depreciation Transmission Plant	(10,802,944)	$ 12,719,086
Accumulated Provision for Depreciation Subfunctional Category:		
Pool Transmission Facilities (PTF)	Not Provided	$ 8,072,477
Non-Pool Transmission Facilities (NPTF)	Not Provided	1,449,026
Reliability Upgrade (Pool Supported PTF/NPTF TBD)	Not Provided	2,429,492
Amounts excluded under the LNS Tariff	Not Provided	768,090
Total Accumulated Provision	(10,802,944)	$ 12,719,085
Accumulatedd Deferred Taxes	$ 12,444,909	$ 12,587,053
Pool Transmission Facilities (PTF)	Not Provided	3,666,425.95
Non-Pool Transmission Facilities (NPTF)	Not Provided	498,821.75
Reliability Upgrade (Pool Supported PTF/NPTF TBD)	Not Provided	4,976,670.02
Amounts excluded under the LNS Tariff (includeds CIAC related)	Not Provided	3,445,134.47
Total Accumulated Deferred Taxes	$ 12,444,909	$ 25,174,105

EXPENSES			**Annual Total**
Taxes Other Than Income Taxes - Property Taxes	$ 500,256	$ 602,199	$ 1,102,455
Taxes Other Than Income Taxes - Payroll Taxes	$ 4,811	0	4811
Property Insurance Expense	$ 10,978	$ 19,337	$ 30,315
Regulatory Commission Expense	82,233	-	82,233
Other A&G Expenses	109,976	316,494	426,470
Total Administrative and General Expenses	$ 203,187	$ 335,831	$ 539,018
Transmission Wages and Salaries	$ 29,647	-	29,647
Administrative and General Wages and Salaries	30,799	104,421	135,220
Total Wages and Salaries	$ 60,446	$ 104,421	$ 164,867
Depreciation Expense	$ 1,005,662	$ 1,079,114	$ 2,084,776
Pool Transmission Facilities (PTF)	321,958	451,160	773,118
Non-Pool Transmission Facilities (NPTF)	49,723	69,967	119,690
Reliability Upgrade (Pool Supported PTF/NPTF TBD)	611,686	527,324	1,139,010
Amounts excluded under the LNS Tariff	22,294	30,663	52,957
	$ 1,005,662	$ 1,079,114	$ 2,084,776
Station Expense - Support Payments	$ 114,915	$ 418,115	$ 533,030
Station Expense - Other	75,748	233,792	$ 309,540
Maintenance of Station Equipment	$ 1,269,799	$ 1,362,899	$ 2,632,698

FERC Account				
403	Depreciation Expense	$ 1,005,662	$ 1,079,114	$ 2,084,776
408.1	Taxes Other than Income Taxes - Payroll Taxes	4,811	0	4,811
408.1	Taxes Other than Income Taxes - Property Taxes	500,256	602,199	1,102,455
409.1	Income Taxes	(1,064,936)		(1,064,936)
409.2	Income Taxes	-		-
410.1	Provision for Deferred Income Taxes	1,141,412		1,141,412
411.1	Provision for Deferred Income Taxes - Credit	-		-
419	Interest Income	(363)		(363)
431	Interest Expense	612,772		612,772
456	Tariff Revenue	(3,975,540)		(3,975,540)
562	Station Expense - Support Payments	114,915	418,115	533,030
562	Station Expense - Other	75,748	233,792	309,540
570	Maintenance of Station Equipment	1,269,799	1,362,899	2,632,698
920	Administrative and General Salaries	6,426	104,421	110,847
921	A&G - Office Supplies & Expenses	22,890	13,834	36,724
922	A&G / Overhead	23,565	-	23,565
923	Outside Services	50,833	189,105	239,938
924	Property Insurance	10,978	19,337	30,315
925	Employee Worker Comp Ins.	613		613
926	Pension & Welfare	5,650		5,650
928	Regulatory Commission Expense	82,233	-	82,233

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

Submitted on: 18-May-11

Revenue Requirements for (year): June 1, 2011 - May 31, 2012

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

		Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	=	95,958,156	(a)	415,152,296	(g)
Total of Attachment F - Section J - Support Revenue		1,794,442	(b)	0	(h)
Total of Attachment F - Section K - Support Expense		3,431,500	(c)	0	(i)
Total of Attachment F - Section (L through O)		(3,904,049)	(d)	12,835,496	(j)
Sub Total - Sum (A through I) - J + K + (L through O)		93,691,165	(e)=(a)-(b)+(c)+(d)	427,987,792	(k)=(g)-(h)+(i)+(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)		N/A	(f)	81,075,000	(l)
Annual True-up (per Attachment C to Attachment F Implementation Rule)		(2,289,708)	(m)	(32,897,534)	(n)
Adjusted Sub Total (Sub Total + True-up)		91,401,457	(o) = (e)+(f)+(m)	476,165,258	(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)				567,566,715	(q) = (o) + (p)

Northeast Utilities System Companies'
Annual Revenue Requirements of PTF Facilities
2010
for Rates billed June 1, 2011 - May 31, 2012
Pre-1997

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	CL&P	PSNH	WMECO	Total	Reference
1	Transmission Plant	(A)(1)(a)	381,636,225	95,042,146	65,193,949	541,872,320	w/s 3A,3B,3C line 1
2	General Plant	(A)(1)(b)	10,849,497	7,635,092	4,495,665	22,980,254	w/s 3A,3B,3C line 2
3	Plant Held For Future Use	(A)(1)(c)	261,932	1,386,004	7,968,447	9,616,383	w/s 3A,3B,3C line 4
4	Total Plant (Lines 1+2+3)		392,747,654	104,063,242	77,658,061	574,468,957	
5	Accumulated Depreciation	(A)(1)(d)	61,894,866	21,790,964	16,679,527	100,365,357	w/s 3A,3B,3C line 7
6	Accumulated Deferred Income Taxes	(A)(1)(e)	30,437,608	14,977,068	9,757,325	55,172,001	w/s 3A,3B,3C line 10
7	Loss On Reacquired Debt	(A)(1)(f)	763,428	391,632	27,356	1,182,416	w/s 3A,3B,3C line 11
8	Other Regulatory Assets	(A)(1)(g)	3,429,350	1,074,842	130,370	4,634,562	w/s 3A,3B,3C line 15
9	Net Investment (Line 4-5-6+7+8)		304,607,958	68,761,684	51,378,935	424,748,577	
10	Prepayments	(A)(1)(h)	3,954,868	1,851,980	364,750	6,171,598	w/s 3A,3B,3C line 16
11	Materials & Supplies	(A)(1)(i)	3,085,985	3,050,530	368,770	6,505,285	w/s 3A,3B,3C line 17
12	Cash Working Capital	(A)(1)(j)	1,555,728	627,155	456,280	2,639,163	w/s 3A,3B,3C line 24
13	Total Investment Base (Line 9+10+11+12)		313,204,539	74,291,349	52,568,735	440,064,623	
	II. REVENUE REQUIREMENTS						
14	Investment Return and Income Taxes	(A)	40,016,296	9,464,614	6,760,876	56,241,786	w/s 2A,2B,2C
15	Depreciation Expense	(B)	9,032,412	2,210,857	1,206,852	12,450,121	w/s 4ABC line 3
16	Amortization of Loss on Reacquired Debt	(C)	66,747	37,946	3,684	108,377	w/s 4ABC line 4
17	Investment Tax Credit	(D)	(95,758)	(2,058)	(16,821)	(114,637)	w/s 4ABC line 5
18	Property Tax Expense	(E)	4,664,639	2,179,624	811,570	7,655,833	w/s 4ABC line 8
19	Payroll Tax Expense	(F)	75,935	36,580	27,912	140,427	w/s 4ABC line 19
20	Operation & Maintenance Expense	(G)	5,112,226	2,382,452	1,469,018	8,963,696	w/s 4ABC line 17
21	Administrative & General Expense	(H)	6,809,597	1,931,630	1,771,326	10,512,553	w/s 4ABC line 18
22	Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	
23	Transmission Support Revenue	(J)	(1,428,602)	(365,840)	-	(1,794,442)	w/s 7
24	Transmission Support Expense	(K)	1,952,603	1,068,999	409,898	3,431,500	w/s 7
25	Transmission Related Expense from Generators	(L)	-	-	-	-	
26	Transmission Related Taxes and Fees Charge	(M)	3,049,676	28,904	3,141	3,081,721	Attachment B line 14
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(382,587)	(78,591)	(55,199)	(516,377)	Attachment C line 9
28	Transmission Rents Received from Electric Property	(O)	(4,390,902)	(1,730,163)	(348,328)	(6,469,393)	
29	Total Revenue Requirements (Line 14 thru 28)		64,482,282	17,164,954	12,043,929	93,691,165	

Worksheet 1B

Northeast Utilities System Companies'
Annual Revenue Requirements of PTF Facilities
2010
for Rates billed June 1, 2011 - May 31, 2012
Post - 1996

Line No.		Attachment F Reference Section:	CL&P	PSNH	WMECO	Total	Reference
	I. INVESTMENT BASE						
1	Transmission Plant	(A)(1)(a)	1,871,996,830	306,578,543	107,886,844	2,286,462,217	w/s 3A,3B,3C line 1
2	General Plant	(A)(1)(b)	53,218,723	24,628,555	7,439,700	85,286,978	w/s 3A,3B,3C line 2
3	Plant Held For Future Use	(A)(1)(c)	1,284,823	4,470,840	13,186,671	18,942,334	w/s 3A,3B,3C line 4
4	Total Plant (Lines 1+2+3)		1,926,500,376	335,677,938	128,513,215	2,390,691,529	
5	Accumulated Depreciation	(A)(1)(d)	303,605,370	70,291,220	27,602,296	401,498,886	w/s 3A,3B,3C line 7
6	Accumulated Deferred Income Taxes	(A)(1)(e)	149,301,904	48,311,604	16,147,014	213,760,522	w/s 3A,3B,3C line 10
7	Loss On Reacquired Debt	(A)(1)(f)	3,744,752	1,263,288	45,270	5,053,310	w/s 3A,3B,3C line 11
8	Other Regulatory Assets	(A)(1)(g)	16,821,574	3,467,122	215,744	20,504,440	w/s 3A,3B,3C line 15
9	Net Investment (Line 4-5-6+7+8)		1,494,159,428	221,805,524	85,024,919	1,800,989,871	
10	Prepayments	(A)(1)(h)	19,399,334	5,973,940	603,610	25,976,884	w/s 3A,3B,3C line 16
11	Materials & Supplies	(A)(1)(i)	15,137,306	9,840,108	610,263	25,587,677	w/s 3A,3B,3C line 17
12	Cash Working Capital	(A)(1)(j)	7,309,834	1,739,494	670,290	9,719,618	w/s 3A,3B,3C line 24
13	Total Investment Base (Line 9+10+11+12)		1,536,005,902	239,359,066	86,909,082	1,862,274,050	
	II. REVENUE REQUIREMENTS						
14	Investment Return and Income Taxes	(A)	196,246,412	30,494,106	11,177,394	237,917,912	w/s 2A,2B,2C
15	Depreciation Expense	(B)	44,305,596	7,131,572	1,997,172	53,434,340	w/s 4ABC line 3
16	Amortization of Loss on Reacquired Debt	(C)	327,406	122,404	6,096	455,906	w/s 4ABC line 4
17	Investment Tax Credit	(D)	(469,709)	(6,640)	(27,836)	(504,185)	w/s 4ABC line 5
18	Property Tax Expense	(E)	22,880,889	7,030,824	1,343,035	31,254,748	w/s 4ABC line 8
19	Payroll Tax Expense	(F)	372,475	117,995	46,191	536,661	w/s 4ABC line 19
20	Operation & Maintenance Expense	(G)	25,076,381	7,685,086	2,431,020	35,192,487	w/s 4ABC line 17
21	Administrative & General Expense	(H)	33,402,288	6,230,869	2,931,298	42,564,455	w/s 4ABC line 18
22	Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	
23	Transmission Related Expense from Generators	(L)		-	-	-	
24	Transmission Related Taxes and Fees Charge	(M)	14,959,205	93,235	5,198	15,057,638	Attachment B line 16
25	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(1,877,228)	(253,579)	(91,335)	(2,222,142)	Attachment C line 10
26	Total Revenue Requirements (Line 14 thru 25)		335,223,715	58,645,872	19,818,233	413,687,820	

Northeast Utilities System Companies'

Annual Revenue Requirements of post-2003 PTF Incremental Return

2010

for Rates billed June 1, 2011 - May 31, 2012

Line	I. INVESTMENT BASE	CL&P	PSNH	WMECO	Total	Reference
1	Transmission Plant	$ 1,578,952,553	$ 124,340,140	$ 12,306,997	$ 1,715,599,690	Attachment D,D1,D2
2	Accumulated Depreciation	$ 97,333,833	$ 9,385,992	$ 1,285,836	$ 108,005,661	Attachment D,D1,D2
3	Accumulated Deferred Income Taxes	$ 88,364,970	$ 9,955,983	$ 1,440,389	$ 99,761,342	
4	Net Investment (Line 1-2-3)	$ 1,393,253,750	$ 104,998,165	$ 9,580,772	$ 1,507,832,687	
	II. INCREMENTAL RETURN					
5	Incremental Revenue Requirements	$ 11,681,039	$ 935,670	$ 80,399	$ 12,697,108	w/s 2A,2B,2C Post 2003

Northeast Utilities System Companies'
Annual Revenue Requirements of Incremental Return
For M-N Advance Technology
for Rates billed June 1, 2011 - May 31, 2012

Line	I. INVESTMENT BASE	CL&P	Reference
1	Transmission Plant	$ 420,588,007	Attachment E
2	Accumulated Depreciation	$ 15,203,100	Attachment E
3	Accumulated Deferred Income Taxes	$ 16,332,907	
4	Net Investment (Line 1-2-3)	$ 389,052,000	
	II. INCREMENTAL RETURN		
5	Incremental Revenue Requirements	$ 1,500,457	w/s 2A M-N Adv Tech

Northeast Utilities System Companies'
Annual Revenue Requirements of Incremental Return
For NEEWS
for Rates billed June 1, 2011 - May 31, 2012

Line	I. INVESTMENT BASE		CL&P	Reference
1	Transmission Plant	$	12,520,208	Attachment F
2	Accumulated Depreciation	$	149,168	Attachment F
3	Accumulated Deferred Income Taxes	$	2,520,578	
4	Net Investment (Line 1-2-3)	$	9,850,462	
	II. INCREMENTAL RETURN			
5	Incremental Revenue Requirements	$	102,407	w/s 2A NEEWS

Worksheet 1F

Northeast Utilities System Companies'
Forecasted Transmission Revenue Requirements of PTF Facilities
Year 2011 Estimates
Post-1996

Line No.	I.	**FORECASTED TRANSMISSION REVENUE REQUIREMENTS**	Attachment F **Reference**	**CL&P**	**PSNH**	**WMECO**	**Total NU**	Reference
1		Forecasted Transmission Plant Additions (excl. Localized)	App. C	$ 30,744,000 (a)	$ 60,100,000	$ 56,892,000	$ 147,736,000	Attachment G
2		Carrying Charge Factor (line 18)	App. C	17.21%	19.18%	18.45%		
3		**Forecasted Transmission Revenue Requirements** (Lines 1 * 2)		$ 5,291,000	$ 11,527,000	$ 10,497,000	$ 27,315,000	
4		Forecasted NEEWS CWIP (a)		$ 137,010,000		$ 250,362,000	$ 387,372,000	
5		NEEWS Cost of Capital Rate (line 21) (b)		13.82%		13.91%		
6		**Forecasted Transmission Rev. Req. for CWIP** (Lines 4 * 5)		$ 18,935,000		$ 34,825,000	$ 53,760,000	
7		**Total Forecasted Transmission Revenue Requirements** (Lines 3 + 6)		$ 24,226,000	$ 11,527,000	$ 45,322,000	$ 81,075,000	
	II.	**CARRYING CHARGE FACTOR (Post 96) (*)**						
8		Investment Return and Income Taxes	(A)	$ 196,246,412	30,494,106	11,177,394	237,917,912	w/s 1B line 14
9		Depreciation Expense	(B)	44,305,596	7,131,572	1,997,172	53,434,340	w/s 1B line 15
10		Amortization of Loss on Reacquired Debt	(C)	327,406	122,404	6,096	455,906	w/s 1B line 16
11		Investment Tax Credit	(D)	(469,709)	(6,640)	(27,836)	(504,185)	w/s 1B line 17
12		Property Tax Expense	(E)	22,880,889	7,030,824	1,343,035	31,254,748	w/s 1B line 18
13		Payroll Tax Expense	(F)	372,475	117,995	46,191	536,661	w/s 1B line 19
14		Operation & Maintenance Expense	(G)	25,076,381	7,685,086	2,431,020	35,192,487	w/s 1B line 20
15		Administrative & General Expense	(H)	33,402,288	6,230,869	2,931,298	42,564,455	w/s 1B line 21
16		Total Expenses (Lines 4 thru 11)		$322,141,738	$58,806,216	$19,904,370	$400,852,324	
17		PTF Transmission Plant		$1,871,996,830	$306,578,543	$107,886,844	$2,286,462,217	w/s 1B line 1
18		Carrying Charge Factor (Lines 12/13)		17.21%	19.18%	18.45%	17.53%	
19		Cost of Capital Rate - 11.64% ROE		12.78%		12.86%		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		13.82%		13.91%		

(*) 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.

(a) Line 1 for CL&P reflects an estimate of the sale of Middletown-Norwalk assets to CTMEEC.

Worksheet 1G

Northeast Utilities System Companies'
Transmission Revenue Requirements of PTF Facilities
2010 True-up
Pre-97 and Post-1996

Line	I. ANNUAL TRUE-UP	PRE-97	POST-96	TOTAL	
1	Transmission Revenue Requirements (as billed)	93,509,035	436,309,962	529,818,997	ATRR - Prior Year
2	True-up 2010 Actual Annual RR @ 11.64% ROE	93,691,165	427,987,792	521,678,957	PTF Pre and Post on ATRR
3	Total Rate Year Surcharge/(Refund) (Line 2 - 1)	182,130	(8,322,170)	(8,140,040)	

Northeast Utilities System Companies'
FERC Interest Calculation associated with Surcharge / (Refund)
Transmission Revenue Requirements of PTF Facilities
PRE-97 / Post 96

	Surcharge / (Refund)
Pre	182,130
Post	(8,322,170)

Initial Billing Period	Balance Pre 97	Balance Post 96	FERC Monthly Interest Rate	Interest Pre 97	Interest Post 96
June 2010	$ 182,130	$ (8,322,170)	0.27%	$ 492	$ (22,470)
July 2010	$ 182,622	$ (8,344,640)	0.28%	$ 511	$ (23,365)
August 2010	$ 182,622	$ (8,344,640)	0.28%	$ 511	$ (23,365)
September 2010	$ 182,622	$ (8,344,640)	0.27%	$ 493	$ (22,531)
October 2010	$ 184,137	$ (8,413,901)	0.28%	$ 516	$ (23,559)
November 2010	$ 184,137	$ (8,413,901)	0.27%	$ 497	$ (22,718)
December 2010	$ 184,137	$ (8,413,901)	0.28%	$ 516	$ (23,559)
January 2011	$ 185,666	$ (8,483,737)	0.28%	$ 520	$ (23,754)
February 2011	$ 185,666	$ (8,483,737)	0.25%	$ 464	$ (21,209)
March 2011	$ 185,666	$ (8,483,737)	0.28%	$ 520	$ (23,754)
April 2011	$ 187,170	$ (8,552,454)	0.27%	$ 505	$ (23,092)
May 2011	$ 187,170	$ (8,552,454)	0.28%	$ 524	$ (23,947)
Total Surcharge/(Refund)				**$ 188,199**	**$ (8,599,493)**

	Interest	Principal	Total (check)	variance
Pre 97	$ 6,069	$ 182,130	$ 188,199	$ -
Post 96	$ (277,323)	$ (8,322,170)	$ (8,599,493)	$ -
	$ (271,254)	$ (8,140,040)	$ (8,411,294)	

Worksheet 2A

Connecticut Light & Power Company (CL&P)
Investment Return and Income Taxes
2010
Pre 97

for Rates billed June 1, 2011 - May 31, 2012

		CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	2,318,940,090	47.99%	5.89%	2.83%	
PREFERRED STOCK	$	116,665,523	2.41%	5.27%	0.13%	0.13%
COMMON EQUITY	$	2,397,008,715	49.60%	11.64%	5.77%	5.77%
TOTAL INVESTMENT RETURN	$	4,832,614,328	100.00%		8.73%	5.90%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.08730

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

= 0.0590 +((95,758) + 342,399) / 313,204,539) x 0.35)
(1 - 0.35)

= 0.0321933

(c) State Income Tax = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate
(1 - State Income tax Rate)

= 0.0590 +((95,758) + 342,399) / 313,204,539) + 0.0321933)* 0.0825
(1 - 0.0825)

= 0.0082708

(a)+(b)+(c) Cost of Capital Rate = 0.1277641

		Pre-1997 PTF	
INVESTMENT BASE	$	313,204,539	From Worksheet 1, line 13
x Cost of Capital Rate		0.1277641	
= Investment Return and Income Taxes	$	40,016,296	To Worksheet 1, line 14

Connecticut Light & Power Company (CL&P)
Investment Return and Income Taxes
2010
POST-96
for Rates billed June 1, 2011 - May 31, 2012

	CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 2,318,940,090	47.99%	5.89%	2.83%	
PREFERRED STOCK	$ 116,665,523	2.41%	5.27%	0.13%	0.13%
COMMON EQUITY	$ 2,397,008,715	49.60%	11.64%	5.77%	5.77%
TOTAL INVESTMENT RETURN	$ 4,832,614,328	100.00%		8.73%	5.90%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.08730

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

= 0.0590 +((469,709) + 1,679,529) / 1,536,005,902) x 0.35)
(1 - 0.35)

= 0.0321933

(c) State Income Tax = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate
(1 - State Income tax Rate)

= 0.0590 +((469,709) + 1,679,529) / 1,536,005,902) + 0.0321933)* 0.0825
(1 - 0.0825)

= 0.0082708

(a)+(b)+(c) Cost of Capital Rate = 0.1277641

	Post - 1996 PTF	
INVESTMENT BASE	$ 1,536,005,902	From Worksheet 1, line 13
x Cost of Capital Rate	0.1277641	
= Investment Return and Income Taxes	$ 196,246,412	To Worksheet 1, line 14

Connecticut Light & Power Company (CL&P)
Investment Return and Income Taxes
Post 2003
Incremental ROE Adder For RSP Projects

	CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 2,318,940,090	47.99%	#N/A		
PREFERRED STOCK	116,665,523	2.41%			
COMMON EQUITY	2,397,008,715	49.60%	1.00%	0.50%	0.50%
TOTAL INVESTMENT RETURN	$ 4,832,614,328	100.00%		0.50%	0.50%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0050

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

= $\dfrac{0.0050 + ((0 + 0) / 1{,}393{,}253{,}750) \times 0.35)}{(1 - 0.35)}$

= 0.0026923

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

= $\dfrac{0.0050 + ((0 + 0) / 1{,}393{,}253{,}750) + 0.0026923)^{*}\ 0.0825}{(1 - 0.0825)}$

= 0.0006917

(a)+(b)+(c) Cost of Capital Rate = 0.0083840

	(post-2003 PTF)	
INVESTMENT BASE	$ 1,393,253,750	From Worksheet 1 Line 4
x Cost of Capital Rate	0.0083840	
= Investment Return and Income Taxes	11,681,039	To Worksheet 1a Line 5

Worksheet 2A M-N Adv Tech

Connecticut Light & Power Company (CL&P)
Investment Return and Income Taxes
Incremental ROE For M-N Advanced Technology

	CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 2,318,940,090	47.99%	#N/A		
PREFERRED STOCK	$ 116,665,523	2.41%			
COMMON EQUITY	$ 2,397,008,715	49.60%	0.46%	0.23%	0.23%
TOTAL INVESTMENT RETURN	$ 4,832,614,328	100.00%		0.23%	0.23%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0023

(b) Federal Income Tax

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

$$= \frac{0.0023 + ((0 + 0) / 389{,}052{,}000) \times 0.35)}{(1 - 0.35)}$$

= 0.0012385

(c) State Income Tax

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

$$= \frac{0.0023 + ((0 + 0) / 389{,}052{,}000) + 0.0012385)^{*} 0.0825}{(1 - 0.0825)}$$

= 0.0003182

(a)+(b)+(c) Cost of Capital Rate = 0.0038567

	(M-N Adv Tech)	
INVESTMENT BASE	$ 389,052,000	From Worksheet 1 Line 4
x Cost of Capital Rate	0.0038567	
= Investment Return and Income Taxes	$ 1,500,457	To Worksheet 1a Line 5

CL&P - 2A -Adv tech

Connecticut Light & Power Company (CL&P)
Investment Return and Income Taxes
Incremental ROE For NEEWS

	CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 2,318,940,090	47.99%	#N/A		
PREFERRED STOCK	$ 116,665,523	2.41%			
COMMON EQUITY	$ 2,397,008,715	49.60%	1.25%	0.62%	0.62%
TOTAL INVESTMENT RETURN	$ 4,832,614,328	100.00%		0.62%	0.62%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0062

(b) Federal Income Tax

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

$$= \frac{0.0062 + ((0 + 0) / 9{,}850{,}462) \times 0.35)}{(1 - 0.35)}$$

$$= 0.0033385$$

(c) State Income Tax

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

$$= \frac{0.0062 + ((0 + 0) / 9{,}850{,}462) + 0.0033385)^{*}\ 0.0825}{(1 - 0.0825)}$$

$$= 0.0008577$$

(a)+(b)+(c) Cost of Capital Rate = 0.0103962

	(NEEWS)	
INVESTMENT BASE	$ 9,850,462	From Worksheet 1 Line 4
x Cost of Capital Rate	0.0103962	
= Investment Return and Income Taxes	$ 102,407	To Worksheet 1a Line 5

Worksheet 3A

Connecticut Light & Power Company (CL&P)
Rate Base Items
Calendar Year 2010

					PRE-97 PTF		POST-96 PTF		
Line No.		(1) Total	(2) Wage/Plant Allocation Factors (a)	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	(6) PTF Allocation Factor (b)	(7) = (3)*(6) PTF Allocated	Reference
	Transmission Plant								
1	Transmission Plant					381,636,225		1,871,996,830	Attachment A
2	General Plant	72,356,514		72,356,514	14.9945%	10,849,497	73.5507%	53,218,723	FF1 page 204 ln. 96, footnote
3	Total (line 1+2)	72,356,514		72,356,514		392,485,722		1,925,215,553	
4	Transmission Plant Held for Future Use	1,746,853 (c)		1,746,853	14.9945%	261,932	73.5507%	1,284,823	(c)
	Transmission Accumulated Depreciation								
5	Transmission Accum. Depreciation	404,482,386		404,482,386	14.9945%	60,650,111	73.5507%	297,499,626	FF1 page 219 ln. 25
6	General Plant Accum.Depreciation	8,301,408		8,301,408	14.9945%	1,244,755	73.5507%	6,105,744	FF1 page 219 ln. 28, footnote
7	Total (line 5+6)	412,783,794		412,783,794		61,894,866		303,605,370	
	Transmission Accumulated Deferred Taxes								
8	Accumulated Deferred Taxes (281 to 283)	(263,289,262)		(263,289,262)	14.9945%	(39,478,908)	73.5507%	(193,651,095)	FF1 page 274 ln. 9 FN & 276 ln. 19 footnote
9	Accumulated Deferred Taxes (190)	60,297,443 (d)		60,297,443	14.9945%	9,041,300	73.5507%	44,349,191	(d)
10	Total (line 8+9)	(202,991,819)		(202,991,819)		(30,437,608)		(149,301,904)	
11	Transmission loss on Reacquired Debt	5,091,389		5,091,389	14.9945%	763,428	73.5507%	3,744,752	FF1 page 110 ln. 81, footnote
	Other Regulatory Assets								
12	FAS 106	-		-	14.9945%	-	73.5507%	-	FF1 page 232
13	FAS 109	25,425,974		25,425,974	14.9945%	3,812,498	73.5507%	18,700,982	FF1 page 232 ln. 10, footnote
14	Other Regulatory Liabilities (254.DK)	(2,555,255)		(2,555,255)	14.9945%	(383,148)	73.5507%	(1,879,408)	FF1 page 278 ln. 5, footnote
15	Total (line 12+13+14)	22,870,719		22,870,719		3,429,350		16,821,574	
16	Transmission Prepayments (165)	26,375,458		26,375,458	14.9945%	3,954,868	73.5507%	19,399,334	FF1 page 110 ln. 57, footnote
17	Transmission Materials and Supplies	20,580,777		20,580,777	14.9945%	3,085,985	73.5507%	15,137,306	FF1 page 227 ln. 8
18	Cash Working Capital								
19	Operation & Maintenance Expense					5,112,226		25,076,381	W/S 4A, Line 17
20	Administrative & General Expense					6,809,597		33,402,288	W/S 4A, Line 18
21	Transmission Support Expense					524,001		-	W/S 7
22	Subtotal (line 19+20+21)					12,445,824		58,478,669	
23						0.125		0.125	x 45 / 360
24	Total (line 22 * line 23)					1,555,728		7,309,834	

(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	33,143,825	FF1 page 214 ln. 11
	Less Third Underground Conduit Duct	31,396,972	
		1,746,853	

(d)	Account 190	85,019,590	FF1 page 234 ln. 18, footnote
	Less Reserve for Disputed Transactions	24,722,147	
	Total Account 190	60,297,443	

Connecticut Light & Power Company (CL&P)
Expense Items
Calendar Year 2010

					PRE-97 PTF		POST-96 PTF		
Line No.		(1) Total	(2) Wage/Plant Allocation Factors (a)	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) Pre-97 PTF Allocated	(6) PTF Allocation Factor (b)	(7) = (3)*(6) Post-96 PTF Allocated	Reference
	Depreciation Expense								
1	Transmission Depreciation	57,754,620		57,754,620	14.9945%	8,660,016	73.5507%	42,478,927	FF1 page 336 ln. 7
2	General Depreciation	2,483,551		2,483,551	14.9945%	372,396	73.5507%	1,826,669	FF1 page 336 ln. 10, footnote
3	Total (line 1+2)	60,238,171		60,238,171		9,032,412		44,305,596	
4	Amortization of Loss on Reacquired Debt	445,143		445,143	14.9945%	66,747	73.5507%	327,406	FF1 page 114, ln. 64, footnote
5	Amortization of Investment Tax Credits	638,619		638,619	14.9945%	95,758	73.5507%	469,709	FF1 page 266 ln. 8, footnote - difference of PY-CY
	Property Taxes								
6	Transmission Property Taxes	31,109,003		31,109,003	14.9945%	4,664,639	73.5507%	22,880,889	FF1 page 262 ln. 25i, footnote
7	General Property Taxes (c)	-		-	14.9945%	-	73.5507%	-	
8	Total (line 6+7)	31,109,003		31,109,003		4,664,639		22,880,889	
	Transmission Operation and Maintenance								
9	Operation and Maintenance	82,605,899		82,605,899	14.9945%	12,386,342	73.5507%	60,757,217	FF1 page 321 ln. 112
10	Transmission of Electricity by Others - #565	32,000,357		32,000,357	14.9945%	4,798,294	73.5507%	23,536,487	FF1 page 321 ln. 96
11	Load Dispatching - #561	1,301		1,301	14.9945%	195	73.5507%	957	FF1 page 321 ln. 84
12	Account 561.1	3,242,231		3,242,231	14.9945%	486,156	73.5507%	2,384,684	FF1 page 321 ln. 85
13	Account 561.2	5,526,493		5,526,493	14.9945%	828,670	73.5507%	4,064,774	FF1 page 321 ln. 86
14	Account 561.3	1,512,433		1,512,433	14.9945%	226,782	73.5507%	1,112,405	FF1 page 321 ln. 87
15	Account 561.4	6,229,076		6,229,076	14.9945%	934,019	73.5507%	4,581,529	FF1 page 321 ln. 88
16	**Station Expenses & Rents - #562 / #567	-		-	14.9945%	-	73.5507%	-	
17	O&M less lines 10 thru 16	34,094,008		34,094,008		5,112,226		25,076,381	
	Transmission Administrative and General								
18	Administrative and General	45,413,964		45,413,964	14.9945%	6,809,597	73.5507%	33,402,288	FF1 page 320 ln. 197, footnote
19	*Payroll Tax Expense*	*506,419*		506,419	14.9945%	75,935	73.5507%	372,475	
	Federal Unemployment	4,599							FF1 page 262 ln. 3i, footnotes
	FICA	369,277							FF1 page 262 ln. 5i, footnote
	Medicare	104,394							FF1 page 262 ln. 9i, footnote
	CT Unemployment	25,332							FF1 page 262 ln. 15i, footnote
	DC Unemployment	21							FF1 page 262.1 ln. 13i, footnote
	FL Unemployment	1							FF1 page 262.1 ln. 17i, footnote
	GA Unemployment	-							FF1 page 262 footnote
	MA Unemployment	52							FF1 page 262 ln. 32i, footnote
	MA Universal Health	100							FF1 page 262 ln. 33i, footnote
	NH Unemployment	2,602							FF1 page 262.1 ln. 3i, footnote
	NJ Unemployment	-							FF1 page 262 footnote
	NY Unemployment	41							FF1 page 262.1 ln. 9i, footnote
	Total	506,419	To Line 19						

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

(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
2010
Pre 97
for Rates billed June 1, 2011 - May 31, 2012

	CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 828,913,192	47.22%	5.05%	2.38%	
PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	$ 926,447,441	52.78%	11.64%	6.14%	6.14%
TOTAL INVESTMENT RETURN	$ 1,755,360,633	100.00%		8.52%	6.14%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0852

(b) Federal Income Tax =((R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

=(0.0614 +((2,058) + 41,522) / 74,291,349) x 0.35)
(1 - 0.35)

= 0.0333476

(c) State Income Tax =(R.O.E. + +(PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate
(1 - State Income Tax Rate)

=(0.0614 +((2,058) + 41,522) / 74,291,349) + 0.0333476)* 0.085
(1 - 0.085)

= 0.0088510

(a)+(b)+(c) Cost of Capital Rate = 0.1273986

	Pre-1997 PTF	
INVESTMENT BASE	$ 74,291,349	From Worksheet 1, line 13
x Cost of Capital Rate	0.1273986	
= Investment Return and Income Taxes	$ 9,464,614	To Worksheet 1, line 14

Public Service Company of New Hampshire (PSNH)
Investment Return and Income Taxes
2010
Post 96
for Rates billed June 1, 2011 - May 31, 2012

	CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 828,913,192	47.22%	5.05%	2.38%	
PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	$ 926,447,441	52.78%	11.64%	6.14%	6.14%
TOTAL INVESTMENT RETURN	$ 1,755,360,633	100.00%		8.52%	6.14%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0852

(b) Federal Income Tax

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

$$= \frac{(\ 0.0614\ +(\ (6,640)\ +\ 133,938\ )\ /\ 239,359,066\ )\ \text{x}\ 0.35\ )}{(\ 1\ -\ 0.35\ )}$$

= 0.0333479

(c) State Income Tax

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

$$= \frac{(\ 0.0614\ +(\ (6,640)\ +\ 133,938\ )\ /\ 239,359,066\ )\ +\ 0.0333479\ )^{*}\ 0.085}{(\ 1\ -\ 0.085\ )}$$

= 0.0088511

(a)+(b)+(c) Cost of Capital Rate = 0.1273990

	Post - 1996 PTF	
INVESTMENT BASE	$ 239,359,066	From Worksheet 1, line 13
x Cost of Capital Rate	0.1273990	
= Investment Return and Income Taxes	$ 30,494,106	To Worksheet 1, line 14

Public Service Company of New Hampshire
Investment Return and Income Taxes
Post 2003
Incremental ROE Adder For RSP Projects

	CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 828,913,192	47.22%	#N/A		
PREFERRED STOCK	$ -	0.00%			
COMMON EQUITY	$ 926,447,441	52.78%	1.00%	0.53%	0.53%
TOTAL INVESTMENT RETURN	$ 1,755,360,633	100.00%		0.53%	0.53%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0053

(b) Federal Income Tax

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

$$= \frac{(\ 0.0053 + ((\ 0 + 0\ ) / 104{,}998{,}165\ ) \times 0.35\ )}{(\ 1 - 0.35\ )}$$

$$= 0.0028538$$

(c) State Income Tax

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

$$= \frac{(\ 0.0053 + ((\ 0 + 0\ ) / 104{,}998{,}165\ ) + 0.0028538\ )^{*}\ 0.085}{(\ 1 - 0.085\ )}$$

$$= 0.0007575$$

(a)+(b)+(c) Cost of Capital Rate = 0.0089113

	(Post-2003 PTF)	
INVESTMENT BASE	$ 104,998,165	From Worksheet 1 Line 4
x Cost of Capital Rate	0.0089113	
= Investment Return and Income Taxes	$ 935,670	To Worksheet 1a Line 5

Worksheet 3B

Public Service Company of New Hampshire (PSNH)

Rate Base Items

Calendar Year 2010

Line No.		(1) Total	(2) Wage/Plant Allocation Factors (a)	(3) = (1)*(2) Transmission Allocated	PRE-97 PTF (4) PTF Allocation Factor (b)	(5) = (3)*(4) Pre-97 PTF Allocated	POST-96 PTF (6) PTF Allocation Factor (b)	(7) = (3)*(6) Post-96 PTF Allocated	Reference
	Transmission Plant								
1	Transmission Plant					95,042,146		306,578,543	Attachment A1
2	General Plant	34,644,336		34,644,336	22.0385%	7,635,092	71.0897%	24,628,555	FF1 page 204 ln. 96, footnote
3	Total (line 1+2)	34,644,336		34,644,336		102,677,238		331,207,098	
4	Transmission Plant Held for Future Use	6,289,013		6,289,013	22.0385%	1,386,004	71.0897%	4,470,840	FF1 page 214 ln. 11
	Transmission Accumulated Depreciation								
5	Transmission Accum. Depreciation	92,167,773		92,167,773	22.0385%	20,312,395	71.0897%	65,521,793	FF1 page 219 ln. 25
6	General Plant Accum.Depreciation	6,709,027		6,709,027	22.0385%	1,478,569	71.0897%	4,769,427	FF1 page 219 ln. 28, footnote
7	Total (line 5+6)	98,876,800		98,876,800		21,790,964		70,291,220	
	Transmission Accumulated Deferred Taxes								
8	Accumulated Deferred Taxes (281-283)	(72,302,901)		(72,302,901)	22.0385%	(15,934,475)	71.0897%	(51,399,915)	FF1 page 274 ln. 9 FN & 276 ln. 19 footnote
9	Accumulated Deferred Taxes (190)	4,344,246	(c)	4,344,246	22.0385%	957,407	71.0897%	3,088,311	(c)
10	Total (line 8+9)	(67,958,655)		(67,958,655)		(14,977,068)		(48,311,604)	
11	Transmission loss on Reacquired Debt	1,777,034		1,777,034	22.0385%	391,632	71.0897%	1,263,288	FF1 page 110 ln. 81, footnote
	Other Regulatory Assets								
12	FAS 106	-		-	22.0385%	-	71.0897%	-	FF1 page 232
13	FAS 109	4,904,166		4,904,166	22.0385%	1,080,805	71.0897%	3,486,357	FF1 page 232 ln. 1, footnote
14	Other Regulatory Liabilities (254.DK)	(27,058)		(27,058)	22.0385%	(5,963)	71.0897%	(19,235)	FF1 page 278 ln. 1, footnote
15	Total (line 12+13+14)	4,877,108		4,877,108		1,074,842		3,467,122	
16	Transmission Prepayments	8,403,383		8,403,383	22.0385%	1,851,980	71.0897%	5,973,940	FF1 page 110 ln. 57, footnote
17	Transmission Materials and Supplies	13,841,820		13,841,820	22.0385%	3,050,530	71.0897%	9,840,108	FF1 page 227 ln. 8
18	Cash Working Capital								
19	Operation & Maintenance Expense					2,382,452		7,685,086	W/S 4B, Line 17
20	Administrative & General Expense					1,931,630		6,230,869	W/S 4B, Line 18
21	Transmission Support Expense					703,159		-	W/S 7
22	Subtotal (line 19+20+21)					5,017,241		13,915,955	
23						0.125		0.125	x 45 / 360
24	Total (line 22 * line 23)					627,155		1,739,494	

(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	4,373,210	FF1 page 234 ln. 18, footnote
Less Reserve for Disputed Transactions	28,964	
Total Account 190	4,344,246	

Worksheet 4B

Public Service Company of New Hampshire (PSNH)

Expense Items

Calendar Year 2010

Line No.		(1) Total	(2) Wage/Plant Allocation Factors (a)	(3) = (1)*(2) Transmission Allocated	PRE-97 PTF (4) PTF Allocation Factor (b)	PRE-97 PTF (5) = (3)*(4) Pre-97 PTF Allocated	POST-96 PTF (6) PTF Allocation Factor (b)	POST-96 PTF (7) = (3)*(6) Post-96 PTF Allocated	Reference
	Depreciation Expense								
1	Transmission Depreciation	8,171,045		8,171,045	22.0385%	1,800,776	71.0897%	5,808,771	FF1 page 336 ln. 7
2	General Depreciation	1,860,749		1,860,749	22.0385%	410,081	71.0897%	1,322,801	FF1 page 336 ln. 10, footnote
3	Total (line 1+2)	10,031,794		10,031,794		2,210,857		7,131,572	
4	Amortization of Loss on Reacquired Debt	172,182		172,182	22.0385%	37,946	71.0897%	122,404	FF1 page 114, ln. 64, footnote
5	Amortization of Investment Tax Credits	9,340		9,340	22.0385%	2,058	71.0897%	6,640	FF1 page 266 ln. 8, footnote - difference of PY-CY
	Property Taxes								
6	Transmission Property Taxes	9,890,074		9,890,074	22.0385%	2,179,624	71.0897%	7,030,824	FF1 page 262 ln. 23i + ln. 31i + page 262.1 ln. 2i, footnote
7	General Property Taxes (c)	-		-	22.0385%	-	71.0897%	-	
8	Total (line 6+7)	9,890,074		9,890,074		2,179,624		7,030,824	
	Transmission Operation and Maintenance								
9	Operation and Maintenance	33,965,862		33,965,862	22.0385%	7,485,566	71.0897%	24,146,229	FF1 page 321 ln. 112
10	Transmission of Electricity by Others - #565	19,841,800		19,841,800	22.0385%	4,372,835	71.0897%	14,105,476	FF1 page 321 ln. 96
11	Load Dispatching - #561	(616)		(616)	22.0385%	(136)	71.0897%	(438)	FF1 page 321 ln. 84
12	Account 561.1	706,282		706,282	22.0385%	155,654	71.0897%	502,094	FF1 page 321 ln. 85
13	Account 561.2	511,918		511,918	22.0385%	112,819	71.0897%	363,921	FF1 page 321 ln. 86
14	Account 561.3	894		894	22.0385%	197	71.0897%	636	FF1 page 321 ln. 87
15	Account 561.4	2,095,175		2,095,175	22.0385%	461,745	71.0897%	1,489,454	FF1 page 321 ln. 88
16	**Station Expenses & Rents - #562	-		-	22.0385%	-	71.0897%	-	
17	O&M less lines 10 thru 16	10,810,409		10,810,409		2,382,452		7,685,086	
	Transmission Administrative and General								
18	Administrative and General	8,764,798		8,764,798	22.0385%	1,931,630	71.0897%	6,230,869	FF1 page 320 ln. 197, footnote
19	*Payroll Tax Expense*	165,980		165,980	22.0385%	36,580	71.0897%	117,995	
	Federal Unemployment	1,550							FF1 page 262 ln. 3i, footnote
	FICA	123,093							FF1 page 262 ln. 5i, footnote
	Medicare	33,592							FF1 page 262 ln. 8i, footnote
	CT Unemployment	5,903							FF1 page 262.1 ln. 7i, footnote
	DC Unemployment	6							FF1 page 262 ln. 27i, footnote
	FL Unemployment	-							FF1 page 262.1 ln. 27i, footnote
	GA Unemployment	-							FF1 page 262
	MA Unemployment	14							FF1 page 262.1 ln. 15i, footnote
	MA Universal Health	26							FF1 page 262.1 ln. 16i, footnote
	NH Unemployment	1,785							FF1 page 262 ln. 15i, footnote
	NJ Unemployment	-							FF1 page 262
	NY Unemployment	11							FF1 page 262.1 ln. 22i, footnote
	Total	165,980	To Line 19						

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

(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.

Worksheet 2C

Western Massachusetts Electric Company (WMECO)
Investment Return and Income Taxes
Pre 97
for Rates billed June 1, 2011 - May 31, 2012

	CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 340,435,029	48.77%	6.27%	3.06%	
PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	$ 357,583,697	51.23%	11.64%	5.96%	5.96%
TOTAL INVESTMENT RETURN	$ 698,018,726	100.00%		9.02%	5.96%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0902

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

= (0.0596 +((16,821) + 12,226) / 52,568,735) x 0.35)
(1 - 0.35)

= 0.0320452

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate
(1 - State Income Tax Rate)

= (0.0596 +((16,821) + 12,226) / 52,568,735) + 0.0320452)* 0.065
(1 - 0.065)

= 0.0063650

(a)+(b)+(c) Cost of Capital Rate = 0.1286102

	Pre-1997 PTF	
INVESTMENT BASE	$ 52,568,735	From Worksheet 1, line 13
x Cost of Capital Rate	0.1286102	
= Investment Return and Income Taxes	$ 6,760,876	To Worksheet 1, line 14

Western Massachusetts Electric Company (WMECO)
Investment Return and Income Taxes
Post 96
for Rates billed June 1, 2011 - May 31, 2012

	CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 340,435,029	48.77%	6.27%	3.06%	
PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	$ 357,583,697	51.23%	11.64%	5.96%	5.96%
TOTAL INVESTMENT RETURN	$ 698,018,726	100.00%		9.02%	5.96%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0902

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

= (0.0596 +((27,836) + 20,233) / 86,909,082) x 0.35) / (1 - 0.35)

= 0.0320452

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate / (1 - State Income Tax Rate)

= (0.0596 +((27,836) + 20,233) / 86,909,082) + 0.0320452)* 0.065 / (1 - 0.065)

= 0.0063650

(a)+(b)+(c) Cost of Capital Rate = 0.1286102

	Post - 1996 PTF	
INVESTMENT BASE	$ 86,909,082	From Worksheet 1, line 13
x Cost of Capital Rate	0.1286102	
= Investment Return and Income Taxes	$ 11,177,394	To Worksheet 1, line 14

Western Massachusetts Electric Company
Investment Return and Income Taxes
Post 2003
Incremental ROE Adder For RSP Projects

	CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 340,435,029	48.77%	#N/A		
PREFERRED STOCK	$ -	0.00%			
COMMON EQUITY	$ 357,583,697	51.23%	1.00%	0.51%	0.51%
TOTAL INVESTMENT RETURN	$ 698,018,726	100.00%		0.51%	0.51%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0051

(b) Federal Income Tax =

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

$$= \left(\frac{0.0051 + \left(\left(0 + 0 \right) / 9{,}580{,}772 \right) \text{ x } 0.35}{(1 - 0.35)} \right)$$

= 0.0027462

(c) State Income Tax =

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

$$= \left(\frac{0.0051 + \left(\left(0 + 0 \right) / 9{,}580{,}772 \right) + 0.0027462)^{*} \; 0.065}{(1 - 0.065)} \right)$$

= 0.0005455

(a)+(b)+(c) Cost of Capital Rate = 0.0083917

	(Post-2003 PTF)	
INVESTMENT BASE	$ 9,580,772	From Worksheet 1 Line 4
x Cost of Capital Rate	0.0083917	
= Investment Return and Income Taxes	$ 80,399	To Worksheet 1a Line 5

Western Massachusetts Electric Company
Investment Return and Income Taxes
Incremental ROE For NEEWS

	CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 340,435,029	48.77%	#N/A		
PREFERRED STOCK	$ -	0.00%			
COMMON EQUITY	$ 357,583,697	51.23%	1.25%	0.64%	0.64%
TOTAL INVESTMENT RETURN	$ 698,018,726	100.00%		0.64%	0.64%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0064

(b) Federal Income Tax

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

$$= \frac{(0.0064 + ((0 + 0) / 0) \times 0.35)}{(1 - 0.35)}$$

$$= 0.0034462$$

(c) State Income Tax

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

$$= \frac{(0.0064 + ((0 + 0) / 0) + 0.0034462)^{*}\ 0.065}{(1 - 0.065)}$$

$$= 0.0006845$$

(a)+(b)+(c) Cost of Capital Rate = 0.0105307

	(NEEWS)	
INVESTMENT BASE	$ 0	From Worksheet 1 Line 4
x Cost of Capital Rate	0.0105307	
= Investment Return and Income Taxes	$ -	To Worksheet 1a Line 5

Western Massachusetts Electric Company

Rate Base Items

Calendar Year 2010

					PRE-97 PTF		POST-96 PTF		
Line No.		(1) Total	(2) Wage/Plant Allocation Factors (a)	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) Pre-97 PTF Allocated	(6) PTF Allocation Factor (b)	(7) = (3)*(6) Post-96 PTF Allocated	Reference
	Transmission Plant								
1	Transmission Plant					65,193,949		107,886,844	Attachment A2
2	General Plant	13,372,433		13,372,433	33.6189%	4,495,665	55.6346%	7,439,700	FF1 page 204 ln. 96, footnote
3	Total (line 1+2)	13,372,433		13,372,433		69,689,614		115,326,544	
4	Transmission Plant Held for Future Use	23,702,284		23,702,284	33.6189%	7,968,447	55.6346%	13,186,671	FF1 page 214 ln. 12
	Transmission Accumulated Depreciation								
5	Transmission Accum. Depreciation	48,102,633		48,102,633	33.6189%	16,171,576	55.6346%	26,761,707	FF1 page 219 ln. 25
6	General Plant Accum.Depreciation	1,510,910		1,510,910	33.6189%	507,951	55.6346%	840,589	FF1 page 219 ln. 28, footnote
7	Total (line 5+6)	49,613,543		49,613,543		16,679,527		27,602,296	
	Transmission Accumulated Deferred Taxes								
8	Accumulated Deferred Taxes (281-283)	(29,531,566)		(29,531,566)	33.6189%	(9,928,188)	55.6346%	(16,429,769)	FF1 page 274 ln. 9 FN & 276 ln. 19 footnote
9	Accumulated Deferred Taxes (190)	508,236 (c)		508,236	33.6189%	170,863	55.6346%	282,755	(c)
10	Total (line 8+9)	(29,023,330)		(29,023,330)		(9,757,325)		(16,147,014)	
11	Transmission loss on Reacquired Debt	81,370		81,370	33.6189%	27,356	55.6346%	45,270	FF1 page 110 ln. 81, footnote
	Other Regulatory Assets								
12	FAS 106	-		-	33.6189%	-	55.6346%	-	FF1 page 232
13	FAS 109	554,974		554,974	33.6189%	186,576	55.6346%	308,758	FF1 page 232 ln. 10, footnote
14	Other Regulatory Liabilities (254.DK)	(167,187)		(167,187)	33.6189%	(56,206)	55.6346%	(93,014)	FF1 page 278 ln. 5, footnote
15	Total (line 12+13+14)	387,787		387,787		130,370		215,744	
16	Transmission Prepayments	1,084,954		1,084,954	33.6189%	364,750	55.6346%	603,610	FF1 page 110 ln. 57, footnote
17	Transmission Materials and Supplies	1,096,913		1,096,913	33.6189%	368,770	55.6346%	610,263	FF1 page 227 ln. 8
18	Cash Working Capital								
19	Operation & Maintenance Expense					1,469,018		2,431,020	W/S 4C, Line 17
20	Administrative & General Expense					1,771,326		2,931,298	W/S 4C, Line 18
21	Transmission Support Expense					409,898			W/S 7
22	Subtotal (line 19+20+21)					3,650,242		5,362,318	
23						0.125		0.125	x 45 / 360
24	Total (line 22 * line 23)					456,280		670,290	

(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	508,236	FF1 page 234 ln. 18, footnote
	Less Reserve for Disputed Transactions	0	
	Total Account 190	508,236	

Worksheet 4C

Western Massachusetts Electric Company
Expense Items
Calendar Year 2010

Line No.		(1) Total	(2) Wage/Plant Allocation Factors (a)	(3) = (1)*(2) Transmission Allocated	PRE-97 PTF (4) PTF Allocation Factor (b)	PRE-97 PTF (5) = (3)*(4) Pre-97 PTF Allocated	POST-96 PTF (6) PTF Allocation Factor (b)	POST-96 PTF (7) = (3)*(6) Post-96 PTF Allocated	Reference
	Depreciation Expense								
1	Transmission Depreciation	3,332,566		3,332,566	33.6189%	1,120,372	55.6346%	1,854,060	FF1 page 336 ln. 7
2	General Depreciation	257,235		257,235	33.6189%	86,480	55.6346%	143,112	FF1 page 336 ln. 10, footnote
3	Total (line 1+2)	3,589,801		3,589,801		1,206,852		1,997,172	
4	Amortization of Loss on Reacquired Debt	10,958		10,958	33.6189%	3,684	55.6346%	6,096	FF1 page 114, ln. 64, footnote
5	Amortization of Investment Tax Credits	50,033		50,033	33.6189%	16,821	55.6346%	27,836	FF1 page 266 ln. 8, footnote - difference of PY-CY
	Property Taxes								
6	Transmission Property Taxes	2,414,029		2,414,029	33.6189%	811,570	55.6346%	1,343,035	FF1 page 262 ln. 33i, footnote
7	General Property Taxes (c)			-	33.6189%	-	55.6346%	-	
8	Total (line 6+7)	2,414,029		2,414,029		811,570		1,343,035	
	Transmission Operation and Maintenance								
9	Operation and Maintenance	22,716,843		22,716,843	33.6189%	7,637,153	55.6346%	12,638,425	FF1 page 321 ln. 112
10	Transmission of Electricity by Others - #565	17,329,719		17,329,719	33.6189%	5,826,061	55.6346%	9,641,320	FF1 page 321 ln. 96
11	Load Dispatching - #561	1,943		1,943	33.6189%	653	55.6346%	1,081	FF1 page 321 ln. 84
12	Account 561.1	1,953		1,953	33.6189%	657	55.6346%	1,087	FF1 page 321 ln. 85
13	Account 561.2	42,737		42,737	33.6189%	14,368	55.6346%	23,777	FF1 page 321 ln. 86
14	Account 561.3	1,953		1,953	33.6189%	657	55.6346%	1,087	FF1 page 321 ln. 87
15	Account 561.4	968,916		968,916	33.6189%	325,739	55.6346%	539,053	FF1 page 321 ln. 88
16	**Station Expenses & Rents - #562 / #567	-		-	33.6189%	-	55.6346%	-	
17	O&M less lines 10 thru 16	4,369,622		4,369,622		1,469,018		2,431,020	
	Transmission Administrative and General								
18	Administrative and General	5,268,840		5,268,840	33.6189%	1,771,326	55.6346%	2,931,298	FF1 page 320 ln. 197, footnote
19	*Payroll Tax Expense*	83,026		83,026	33.6189%	27,912	55.6346%	46,191	
	Federal Unemployment	804							FF1 page 262 ln. 3i, footnote
	FICA	59,893							FF1 page 262 ln. 5i, footnote
	Medicare	16,890							FF1 page 262 ln. 9i, footnote
	CT Unemployment	3,665							FF1 page 262 ln. 13i, footnote
	DC Unemployment	4							FF1 page 262.1 ln. 8i, footnote
	FL Unemployment	1							FF1 page 262.1 ln. 13i, footnote
	GA Unemployment	-							FF1 page 262
	MA Unemployment	715							FF1 page 262 ln. 23i, footnote
	MA Universal Health	596							FF1 page 262 ln. 28i, footnote
	NH Unemployment	451							FF1 page 262 ln. 38i, footnote
	NJ Unemployment	-							FF1 page 262 footnote
	NY Unemployment	7							
	Total	83,026	To Line 19						

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

(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
Calendar Year 2010
PRE-1997

Line No.	**PTF Transmission Plant Allocation Factor**	CL&P	PSNH	WMECO	TOTAL	Reference
1	PTF Transmission Investment	381,636,225	95,042,146	65,193,949	541,872,320	w/s 3A,3B,3C line 1
2	Total Transmission Investment	2,545,178,926	431,256,026	193,920,257	3,170,355,209	FF1 page 206-207 ln 58
3	Percent Allocation (Line 1/ Line 2)	14.9945%	22.0385%	33.6189%	17.0918%	
	Transmission Wages and Salaries Allocation Factor					
4	Direct Transmission Wages and Salaries	6,035,477	1,250,792	628,426	7,914,695	FF1 page 354 ln 21
5	Affiliated Company Transmission Wages and Salaries	8,532,763	1,218,791	516,127	10,267,681	w/s 6 line 15
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	14,568,240	2,469,583	1,144,553	18,182,376	
7	Total Wages and Salaries	111,160,467	79,441,831	21,998,396	212,600,694	FF1 page 354 ln 28
8	Administrative and General Wages and Salaries	23,128,368	17,642,795	4,531,994	45,303,157	FF1 page 354 ln 27
9	Affiliated Company Wages and Salaries less A&G	47,746,206	12,985,019	8,873,719	69,604,944	w/s 6 line 30
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	135,778,305	74,784,055	26,340,121	236,902,481	
11	Percent Allocation (Line 6 / Line 10)	10.7294%	3.3023%	4.3453%	7.6750%	
	Plant Allocation Factor					
12	Total Transmission Investment (Line 2)	2,545,178,926	431,256,026	193,920,257	3,170,355,209	
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	72,356,514	34,644,336	13,372,433	120,373,283	w/s 3A,3B,3C line 2
14	*= Revised Numerator (Line 12 + Line 13)*	2,617,535,440	465,900,362	207,292,690	3,290,728,492	
15	Total Plant in Service	6,796,392,422	2,525,216,974	890,359,729	10,211,969,125	FF1 206-207 ln 100
16	Percent Allocation (Line 14 / Line 15)	38.5136%	18.4499%	23.2819%	32.2242%	

Northeast Utilities System Companies
Allocation Factors
Calendar Year 2010
POST - 1996

Line No.		CL&P	PSNH	WMECO	TOTAL	Reference
	PTF Transmission Plant Allocation Factor					
1	PTF Transmission Investment	1,871,996,830	306,578,543	107,886,844	2,286,462,217	w/s 3A,3B,3C line 1
2	Total Transmission Investment	2,545,178,926	431,256,026	193,920,257	3,170,355,209	FF1 page 206-207 ln 58
3	Percent Allocation (Line 1/ Line 2)	73.5507%	71.0897%	55.6346%	72.1201%	
	Transmission Wages and Salaries Allocation Factor					
4	Direct Transmission Wages and Salaries	6,035,477	1,250,792	628,426	7,914,695	FF1 page 354 ln 21
5	Affiliated Company Transmission Wages and Salaries	8,532,763	1,218,791	516,127	10,267,681	w/s 6 line 15
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	14,568,240	2,469,583	1,144,553	18,182,376	
7	Total Wages and Salaries	111,160,467	79,441,831	21,998,396	212,600,694	FF1 page 354 ln 28
8	Administrative and General Wages and Salaries	23,128,368	17,642,795	4,531,994	45,303,157	FF1 page 354 ln 27
9	Affiliated Company Wages and Salaries less A&G	47,746,206	12,985,019	8,873,719	69,604,944	w/s 6 line 30
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	135,778,305	74,784,055	26,340,121	236,902,481	
11	Percent Allocation (Line 6 / Line 10)	10.7294%	3.3023%	4.3453%	7.6750%	
	Plant Allocation Factor					
12	Total Transmission Investment (Line 2)	2,545,178,926	431,256,026	193,920,257	3,170,355,209	
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	72,356,514	34,644,336	13,372,433	120,373,283	w/s 3A,3B,3C line 2
14	*= Revised Numerator (Line 12 + Line 13)*	2,617,535,440	465,900,362	207,292,690	3,290,728,492	
15	Total Plant in Service	6,796,392,422	2,525,216,974	890,359,729	10,211,969,125	FF1 206-207 ln 100
16	Percent Allocation (Line 14 / Line 15)	38.5136%	18.4499%	23.2819%	32.2242%	

Northeast Utilities System Companies
Affiliated Company Wages and Salaries
PRE and POST

Line		CL&P	PSNH	WMECO
"Affiliated" Transmission Wages and Salaries (a)				
#560 - 573				
1	560	3,844,579	525,963	219,918
2	561.5 -561.8	631,144	59,453	41,841
3	562	207,261	45,974	14,293
4	563	776	993	0
5	564	2,380	0	0
6	566	0	0	0
7	567	0	0	0
8	568	1,526,103	217,489	89,253
9	569	973,779	153,444	68,814
10	570	967,067	184,445	74,754
11	571	167,432	12,016	4,479
12	572	79,170	0	186
13	573	133,072	19,014	2,589
14 = 1 thru 13	Total Transmission	8,532,763	1,218,791	516,127
15 = Total "Affiliated" Wages and Salaries		59,842,931	15,399,593	10,265,123
Less "Affiliated" Administrative and General Salaries (b)				
#920 - 935				
16	920	12,028,293	2,389,108	1,380,062
17	921	(44,010)	3,129	1,763
18	923	1,545	526	422
19	925	51,262	12,913	4,216
20	926	0	0	0
21	927	0	0	0
22	929	0	0	0
23	931	0	0	0
24	935	59,635	8,898	4,941
25 = 16 thru 24		12,096,725	2,414,574	1,391,404
26 = 15 less 25	Total "Affiliated" less A&G	47,746,206	12,985,019	8,873,719

Worksheet 7

Northeast Utilities Systems Companies
Transmission Support Revenues and Expenses
Calendar Year 2010
Pre 97

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.

			CL&P		PSNH		WMECO		TOTAL	
Participant	PTF Supporting Facilities	FERC Form 1	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 ln. 7		87,147		46,289		18,294		151,730
	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**			-		13,469		-		13,469
	115 kV Wyman 164-167 lines			-		5,055		-		5,055
	115 kV Saco Valley	FF1 page 332		-		0		-		-
										-
EUA	345 kV Carver - Walpole 331 line									-
	345 kV Medway - Bridgewater 344 Line									-
	Northern Rhode Island transmission									-
										-
NEP	**Chester SVC**	FF1 page 332 ln. 13		559,464		297,168		117,445		974,077
	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		-		13,319		-		13,319
	HQ Phase II - AC in MA	FF1 page 332 ln. 6		1,305,992		693,699		274,159		2,273,850
	345 kV Golden Hills-Mystic 349 line									-
	345 kV NH/MA border-Tewksbury 394 line	FF1 page 332		-		-		-		-
	115 kV Read - Washington V148 line									-
										-
NU	**345 kV 363, 369 and 394 Seabrook lines**	FF1 page 330	-		365,840		-		365,840	-
	Fairmont 115 kV Substation	FF1 page 330	-		-		-		0	-
	345 kV Millstone-Manchester 310 line	FF1 page 330.1 ln. 9	1,220,599		-		-		1,220,599	-
	UI Substations	FF1 page 330	-		-		-		0	-
	Black Pond	FF1 page 330.1 ln 10	208,003		-		-		208,003	-
		Total =	1,428,602	1,952,603	365,840	1,068,999	-	409,898	1,794,442	3,431,500
	Amount by which Support Expense exceeds Support Revenues (To Worksheet 3, Line 21, Column 5)			524,001		703,159		409,898		1,637,058

Attachment A

Connecticut Light and Power Company
Substations and Lines
PTF Investment as of 12/31/10 (101 + 106)

	350	352	353	354	355	356	357	358	359	361	362	Grand Total
1976 + PRIOR	22,345,697.52	1,727,411.80	36,877,433.20	17,907,628.44	36,712,161.62	34,033,669.58	817,910.81	5,085,041.03	341,207.64	2,555,204.02	12,232,653.16	170,636,018.83
1977	2,373,502.57	223,870.20	3,287,922.90	0.00	2,193,810.17	1,506,022.44	0.00	363,428.49	0.00	343,370.38	352,237.84	10,644,164.98
1978	4,666,071.53	420,332.25	3,800,826.07	124,018.10	5,791,654.09	5,014,254.09	0.00	0.00	0.00	57,641.76	271,845.48	20,146,643.37
1979	5,599,430.54	0.00	633,712.07	0.00	3,011,212.50	1,408,337.37	0.00	0.00	53,118.62	43,095.34	480,491.91	11,229,398.35
1980	302,113.58	0.00	912,705.45	1,207,553.88	1,165,524.66	1,783,085.97	0.00	0.00	0.00	28,027.62	142,028.35	5,541,039.50
1981	807,294.32	418,975.86	6,664,013.71	3,363,183.07	3,778,233.85	2,871,087.62	0.00	0.00	445,359.14	152,881.47	206,196.91	18,707,225.94
1982	1,319,642.52	10,210.30	795,517.59	0.00	4,342,413.66	3,137,589.63	0.00	0.00	457,303.27	118,505.73	171,622.42	10,352,805.11
1983	143,071.55	97,133.02	2,111,070.78	1,633,362.93	1,373,080.64	943,747.96	0.00	452,348.46	114,420.29	72,470.09	205,513.51	7,146,219.23
1984	23,940.59	127,646.92	2,155,463.67	736,432.67	13,538.77	697,887.08	0.00	0.00	105,693.03	17,076.43	195,277.21	4,072,956.37
1985	0.00	660,642.79	7,468,356.34	254,460.70	12,716,402.36	11,134,043.31	0.00	14,035.59	2,086,693.18	111,988.88	193,366.08	34,639,989.23
1986	17.45	14,703.83	4,524,416.17	0.00	203,272.05	608,619.41	0.00	0.00	7,934.56	59,475.72	186,067.12	5,604,506.32
1987	26,687.13	5,204.20	602,559.68	220,544.60	2,282,408.84	1,192,027.94	0.00	0.00	141,730.14	16,563.28	218,872.28	4,706,598.09
1988	12,321.82	94,884.43	2,801,727.98	0.00	419,496.90	813,077.54	0.00	0.00	247,458.25	160,727.24	492,095.42	5,041,789.58
1989	13,407.54	200,788.02	612,899.27	180,966.57	2,241,153.50	1,818,485.72	0.00	23,806.86	552,449.96	49,141.32	601,103.77	6,294,202.53
1990	15,660.14	175,832.80	7,049,089.16	428,506.43	580,138.86	814,674.48	0.00	0.00	96,769.87	1,409,928.74	2,005,253.15	12,575,853.63
1991	893,384.98	8,638.88	7,813,269.59	92,885.29	6,010,808.09	5,983,734.62	0.00	0.00	1,288,940.98	39,639.54	613,721.09	22,745,023.07
1992	42,485.41	9,996.71	1,684,305.59	0.00	2,596,097.44	1,559,020.21	0.00	0.00	744,782.51	0.00	290,905.76	6,927,593.64
1993	1,193.02	0.00	854,923.66	140,492.94	14,639,277.63	2,889,659.96	0.00	0.00	19,686.26	0.00	74,721.38	18,619,954.85
1994	(15,032.07)	0.00	2,541,923.11	0.00	390,839.13	192,107.76	0.00	0.00	90,525.06	56,536.08	66,403.84	3,323,302.91
1995	2,545.44	36,207.51	170,078.43	0.00	347,481.69	256,664.17	0.00	0.00	0.00	1,730.23	2,174.85	816,882.32
1996	0.00	93,274.62	1,338,881.11	0.00	324,259.63	72,341.50	0.00	0.00	0.00	28,930.55	6,369.27	1,864,056.68
Pre-1997	38,573,435.58	4,325,754.15	94,701,095.51	26,290,035.62	101,133,266.08	78,730,138.36	817,910.81	5,938,660.43	6,794,072.76	5,322,934.41	19,008,920.81	381,636,224.53
1997	39,442.79	38,745.58	4,956,713.80	112,607.52	118,897.46	4,837,106.76	0.00	0.00	0.00	15,101.15	71,326.02	10,189,941.08
1998	(6,147.32)	53,887.91	385,140.85	0.00	113,374.45	105,664.19	0.00	0.00	0.00	15,752.81	25,989.92	693,662.81
1999	0.00	0.00	542,978.40	28,802.26	26,718.64	6,688.86	0.00	0.00	0.00	10,223.59	31,549.56	646,961.30
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	36,617.52	202,917.25	3,482,060.60
2001	379,320.03	240,867.63	17,395,206.54	0.00	1,269,539.97	28,447.99	0.00	0.00	0.00	0.00	26,185.93	19,339,568.09
2002	0.00	101,161.43	5,951,417.18	184,907.20	1,932,736.37	2,939,424.59	0.00	0.00	0.00	147,096.76	151,113.08	11,407,856.61
2003	(30,877.09)	182,195.09	13,860,791.04	55,332.28	8,894,377.90	2,570,587.65	0.00	0.00	0.00	45,247.53	90,123.96	25,667,778.36
2004	605,147.38	1,986,742.91	55,997,320.13	0.00	2,261,294.57	377,603.79	1,058,908.61	1,180,509.94	18,824.61	7,619.33	327,798.94	63,821,770.21
2005	2,842,078.02	4,555,940.89	77,003,069.38	0.00	3,492,551.70	3,110,943.64	16,291,589.29	9,150,257.10	0.00	162,206.93	129,224.20	116,737,861.15
2006	11,343,316.97	7,282,986.24	79,205,651.86	0.00	20,113,526.25	9,020,162.39	20,432,422.46	67,443,769.08	3,924,497.21	965,243.29	870,158.35	220,601,734.11
2007	10,957,686.61	3,568,890.27	77,691,772.08	0.00	81,194,232.70	46,921,204.59	0.00	0.00	29,274.47	19,328.86	116,755.88	220,499,145.46
2008	1,379,859.22	9,474,798.68	211,252,562.82	377,524.85	101,654,739.17	60,195,127.63	355,375,199.80	303,278,988.04	18,143,489.85	221,200.47	231,069.25	1,061,584,559.79
2009	1,325,350.70	6,786,476.39	48,121,096.54	0.00	7,379,093.80	409,822.66	0.00	16,940.16	728,470.07	2,916,492.36	2,334,915.53	70,018,658.21
2010	1,350,094.67	346,204.88	23,128,923.30	0.00	10,251,289.06	10,478,857.77	1,322,123.51	0.00	269,839.02	657.05	157,283.27	47,305,272.54
Post-1996	30,185,272.00	34,618,897.90	618,096,124.72	759,174.11	238,958,755.85	141,007,305.58	394,616,876.70	381,249,468.48	23,175,756.19	4,562,787.62	4,766,411.14	1,871,996,830.30
Grand Total	68,758,707.57	38,944,652.06	712,797,220.24	27,049,209.73	340,092,021.93	219,737,443.94	395,434,787.51	387,188,128.91	29,969,828.95	9,885,722.03	23,775,331.95	2,253,633,054.83

Attachment A1

PSNH

Substations and Lines

PTF Investment as of 12/31/10 (101 + 106)

	350	352	353	354	355	356	357	358	359	361	362	Grand Total
1976 + PRIOR	6,761,262.03	1,531,205.98	10,508,277.50	4,984,250.97	14,365,851.92	13,267,080.09	0.00	0.00	114,874.19	886,502.59	1,369,636.03	53,788,941.30
1977	23,877.28	0.00	72,957.32	0.00	337,362.92	302,087.83	0.00	0.00	0.00	4,063.38	43,386.87	783,735.59
1978	139,169.79	3,244.33	257,263.01	0.00	111,091.68	74,446.32	0.00	0.00	0.00	29,937.53	50,391.42	665,544.09
1979	7,138.78	1,061.97	217,431.56	0.00	22,896.88	8,571.59	0.00	0.00	0.00	117,948.33	79,183.84	454,232.95
1980	1,509,193.04	23,701.20	963,660.37	3,683,253.81	130,557.04	2,447,185.66	0.00	0.00	468,079.93	0.00	4,306.86	9,229,937.91
1981	0.00	0.00	40,597.38	0.00	55,105.42	8,828.28	0.00	0.00	0.00	6,891.61	3,420.82	114,843.50
1982	18.16	0.00	40,257.84	0.00	119,784.62	9,531.48	0.00	0.00	15,557.34	26,343.77	53,569.08	265,062.29
1983	3,023,089.55	4,803.81	553,653.04	0.00	6,712,752.36	4,147,566.73	0.00	0.00	58,959.34	95,643.58	2,406.91	14,598,875.32
1984	1,251.27	0.00	286,278.69	0.00	31,174.37	3,868.27	0.00	0.00	0.00	170,131.02	173,778.97	666,482.60
1985	41.35	0.00	71,640.22	0.00	180,351.54	30,518.62	0.00	0.00	0.00	11,233.11	55,657.65	349,442.49
1986	0.00	575.06	124,851.51	0.00	284,255.28	131,783.31	0.00	0.00	0.00	0.00	11,192.54	552,657.70
1987	462,957.63	0.00	30,706.60	0.00	136,774.99	25,273.81	0.00	0.00	3,785.03	8,266.76	31,586.36	699,351.17
1988	3,609.60	0.00	445.23	965,848.51	956,126.76	1,500,829.53	0.00	0.00	0.00	0.00	13,117.25	3,439,976.88
1989	14,647.25	0.00	182,749.61	0.00	375,064.19	91,236.57	0.00	0.00	1,113.97	577,999.18	634,063.00	1,876,873.77
1990	0.00	5,566.96	164,958.56	0.00	313,894.77	10,127.91	0.00	0.00	3,015.40	0.00	6,649.75	504,213.35
1991	5,325.56	0.00	33,680.81	0.00	321,114.13	58,253.11	0.00	0.00	6,908.16	14,433.00	19,113.65	458,828.41
1992	384.04	0.00	30,221.62	0.00	404,513.81	58,366.32	0.00	0.00	0.00	2,057.58	25,774.32	521,317.69
1993	811,336.61	0.00	428,917.18	0.00	1,506,902.88	1,564,686.24	0.00	0.00	0.00	28,232.50	80,730.40	4,420,805.80
1994	296,026.16	18,681.31	67,770.32	0.00	364,912.43	67,024.43	0.00	0.00	10,622.94	30,185.36	6,499.87	861,722.82
1995	0.00	0.00	96,115.36	0.00	105,310.72	147,016.99	0.00	0.00	0.00	0.00	15,822.89	364,265.96
1996	12,216.10	0.00	441,809.15	0.00	60,177.02	(206,855.54)	0.00	0.00	8,428.10	31,322.70	77,936.65	425,034.17
Pre-1997	13,071,544.20	1,588,840.62	14,614,242.87	9,633,353.29	26,895,975.73	23,747,427.55	0.00	0.00	691,344.40	2,041,191.98	2,758,225.13	95,042,145.77
1997	16,059.00	0.00	166,533.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25,224.76	207,816.79
1998	0.00	0.00	180,500.93	0.00	34,083.95	4,290.69	0.00	0.00	0.00	0.00	2,239.24	221,114.81
1999	0.00	0.00	469,871.03	0.00	435,301.73	35,742.50	0.00	0.00	0.00	5,124.04	12,737.72	958,777.02
2000	1,577.15	0.00	56,646.89	0.00	601,181.18	99,442.88	0.00	0.00	0.00	9,072.86	2,236.17	770,157.12
2001	1,850.00	0.00	1,208,773.13	0.00	1,939,565.20	987,299.93	0.00	0.00	0.00	106,129.43	29,316.27	4,272,933.96
2002	17.06	52,231.53	2,218,947.90	0.00	1,323,131.65	340,583.63	0.00	0.00	0.00	0.00	29,925.52	3,964,837.29
2003	503,591.69	119,707.80	13,826,137.89	0.00	3,907,008.02	1,490,494.91	0.00	0.00	0.00	295,836.88	238,795.42	20,381,572.61
2004	521,822.70	819,524.27	16,860,202.43	0.00	2,905,956.61	944,615.44	0.00	0.00	0.00	44,470.74	109,081.59	22,205,673.79
2005	612,681.03	1,100,240.71	13,017,302.65	0.00	3,316,986.24	1,535,933.75	0.00	0.00	0.00	1,154,057.34	143,934.96	20,881,136.69
2006	361,997.42	413,937.05	14,235,931.34	0.00	4,393,080.74	1,804,750.60	0.00	0.00	0.00	273,834.62	454,553.83	21,938,085.59
2007	3,413.51	416,869.30	21,039,637.74	48,014.31	17,695,104.33	4,429,567.56	0.00	0.00	0.00	502,725.74	841,036.23	44,976,368.72
2008	0.00	8,948,645.80	49,728,979.67	23,769.94	7,688,691.14	4,637,663.29	0.00	0.00	0.00	580,858.86	517,086.51	72,125,695.21
2009	5,203.01	2,077,181.52	47,198,773.21	0.00	7,022,272.21	10,384,455.95	0.00	0.00	7,337.13	375,078.66	212,886.79	67,283,188.48
2010	2,438,979.17	163,761.96	12,840,202.72	0.00	8,202,201.47	2,680,559.07	0.00	0.00	6,469.45	0.00	59,010.78	26,391,184.63
Post-1996	4,467,191.74	14,112,099.94	193,048,440.57	71,784.25	59,464,564.47	29,375,400.20	0.00	0.00	13,806.58	3,347,189.15	2,678,065.80	306,578,542.70
Grand Total	17,538,735.95	15,700,940.57	207,662,683.44	9,705,137.54	86,360,540.20	53,122,827.75	0.00	0.00	705,150.98	5,388,381.14	5,436,290.92	401,620,688.47

Western Massachusetts Electric Company
Substations and Lines
PTF Investment as of 12/31/10 (101 + 106)

	350	352	353	354	355	356	357	358	359	361	362	Grand Total
1976 + prior	9,152,951.65	1,230,372.98	14,583,509.26	1,035,870.02	7,674,929.07	11,445,017.19	31,742.27	1,169,976.09	-	1,571,570.98	2,623,035.46	50,518,974.97
1977	24,338.31	1,980.03	122,867.92	113,901.57	2,058,031.62	2,248,216.53	-	-	-	12,596.00	354,145.06	4,936,077.04
1978	-	-	14,378.75	-	-	7,536.32	-	-	-	212,127.37	32,064.08	266,106.51
1979	10,284.94	-	431,402.66	-	178,455.10	86,353.76	-	-	5,614.05	-	15,962.07	728,072.57
1980	1,449.53	-	786,183.68	-	-	1,909.38	-	-	-	1,239.54	263,629.60	1,054,411.74
1981	12,424.35	-	128,956.46	-	-	-	-	-	-	-	55,748.72	197,129.54
1982	50,999.36	-	278,784.31	-	-	13,901.64	-	-	-	-	86,734.58	430,419.89
1983	-	15,300.56	167,628.09	-	-	-	-	-	-	15,157.37	104,896.83	302,982.85
1984	73,847.45	-	837,393.31	-	72,572.55	132,518.95	-	-	-	43,067.75	338,524.26	1,497,924.28
1985	199,055.53	17,437.12	63,182.09	-	40,356.20	10,366.45	-	-	-	6,579.24	54,025.93	391,002.56
1986	-	-	242,083.67	-	-	61,388.46	-	-	-	6,786.25	-	310,258.37
1987	1,537.04	-	89,130.27	-	-	37,797.17	-	-	-	29,013.55	112,732.22	270,210.25
1988	1,125.58	-	602,451.80	-	39,865.01	33,013.71	-	-	25,912.84	-	264,198.28	966,567.22
1989	1,477.73	-	119,662.85	-	362,317.19	113,378.48	-	-	-	9,708.23	6,708.43	613,252.90
1990	9,163.43	-	21,347.06	-	97,580.99	34,978.81	-	-	-	-	3,548.55	166,618.85
1991	-	-	84,508.82	-	266,055.97	108,030.45	-	-	-	751.42	3,136.14	462,482.80
1992	-	-	334,453.10	-	183,464.03	15,808.38	-	-	-	-	168,907.98	702,633.49
1993	-	-	137,358.10	-	52,120.46	290,094.29	-	-	-	-	39,865.18	519,438.03
1994	-	22,086.54	19,050.90	-	166,096.06	233,890.68	-	-	-	-	10,658.83	451,783.02
1995	-	-	96,045.23	-	3,830.17	-	-	27,888.96	-	21,276.52	-	149,040.88
1996	-	16,412.76	-	-	-	213,574.66	-	-	-	16,625.50	11,948.34	258,561.25
Pre-1997	9,538,654.90	1,303,589.99	19,160,378.34	1,149,771.59	11,195,674.42	15,087,775.31	31,742.27	1,197,865.05	31,526.89	1,946,499.71	4,550,470.55	65,193,949.01
1997	-	-	1,361,299.96	-	414,195.88	2,977,961.82	-	-	-	12,657.29	2,289.11	4,768,404.06
1998	15,233.06	-	18,704.50	-	-	-	-	-	-	11,686.26	59,698.03	105,321.85
1999	-	-	1,756,926.89	-	1,928,894.28	2,490,402.23	-	-	-	-	5,295.13	6,181,518.53
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	-	-	-	-	45,097.48	2,123,161.16
2002	-	77,480.18	3,257,381.14	-	388,521.22	90,676.02	-	-	-	-	59,191.97	3,873,250.53
2003	-	-	2,271,326.13	-	67,136.37	9,154.96	-	-	-	-	29,057.33	2,376,674.79
2004	-	40,552.71	5,089,321.36	-	854,457.36	148,753.14	-	-	4,668.80	77,155.66	163,393.33	6,378,302.36
2005	-	46,631.30	7,820,076.81	-	204,792.77	-	-	-	-	9,496.11	9,689.48	8,090,686.47
2006	-	-	8,645,818.18	-	415,921.15	169,031.15	-	-	22,539.43	34,795.27	133,573.72	9,421,678.90
2007	900.03	-	6,658,589.04	-	198,528.56	691,401.78	-	-	4,728.76	23,890.70	825.78	7,578,864.64
2008	1,762.03	53,365.73	6,268,139.44	-	4,056,325.76	373,039.45	-	-	12,386.05	2,144.18	207,661.85	10,974,824.49
2009	-	261,935.42	8,558,707.78	-	8,375,651.16	1,181,622.03	-	-	-	395,747.16	44,520.29	18,818,183.83
2010	-	-	9,763,466.76	-	17,109,670.13	-	-	-	5,885.39	66,561.72	-	26,945,584.01
Post-1996	17,895.12	482,453.60	63,600,362.66	-	34,088,570.22	8,227,451.42	-	-	75683.48	634,134.36	760,293.49	107,886,844.34
Grand Total	9,556,550.01	1,786,043.59	82,760,740.99	1,149,771.59	45,284,244.64	23,315,226.73	31,742.27	1,197,865.05	107,210.37	2,580,634.07	5,310,764.04	173,080,793.35

Attachment B

Transmission Related Taxes and Fees

Calendar Year 2010

Ln.	Tax - Description	CL&P	PSNH	WMECO	TOTAL	Reference
1	CT Gross Earnings Tax	20,151,980	-	-	20,151,980	FF1 p 262 FN
2	CT Insurance Premium Excise Tax	77,576	3,636	1,692	82,904	
3	NH Excise Tax	-	8,315	-	8,315	
4	Fed. Excise Tax	-	-	-	-	
5	Mass. Excise Tax	33	5	3	41	
6	Corporation Business Tax (B)	-	-	557	557	
7	MA Sales Tax	-	-	3,025	3,025	
8	CT Sales Tax	109,042	7,381	4,066	120,489	
9	NH Business Enterprise Tax	-	111,814	-	111,814	
10	NY Business Franchise Tax	-	-	-	-	
11	Federal Highway use Tax	-	-	-	-	
12	TOTAL (sum of lines 1 to 11)	20,338,631	131,151	9,343	20,479,125	To Total RR Wksht 1
13	Pre-97 %	14.9945%	22.0385%	33.6189%		w/s 5A
14	Total Pre-97 Related Exp. (line 12x13)	3,049,676	28,904	3,141	3,081,721	To w/s 1A
15	Post-96 %	73.5507%	71.0897%	55.6346%		w/s 5B
16	Total Post-96 Related Exp. (line 12x15)	14,959,205	93,235	5,198	15,057,638	To w/s 1B

Attachment C

Short Term Through and Out Revenues

Used in the development of 2010 PTF Revenue Requirements

		CL&P	PSNH	WMECO	TOTAL	Source:
1	**2010 Through and Out Revenues**	2,259,815	332,170	146,534	2,738,519	FF1 pg 328.1 - 330.1
2	Less: LT Revs	-	-	-	-	
3	ST T/O Revenues (Line 1-2)	2,259,815	332,170	146,534	2,738,519	
4	Pre-1997 PTF Plant	381,636,225	95,042,146	65,193,949	541,872,320	Attachment A, A1, A2
5	Post-1996 PTF Plant	1,871,996,830	306,578,543	107,886,844	2,286,462,217	Attachment A, A1, A2
6	Total PTF Plant (line 4+ 5)	2,253,633,055	401,620,689	173,080,793	2,828,334,537	
7	Ratio of Pre to Total (Line 4 / 6)	16.93%	23.66%	37.67%		
8	Ratio of Post to Total (Line 5 / 6)	83.07%	76.34%	62.33%		
		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)	382,587	78,591	55,199	516,377	to w/s 1A
10	Post-1996 Revenue Credit (line 3 * 8)	1,877,228	253,579	91,335	2,222,142	to w/s 1B
11	Total Revenue Credit (line 9+10)	2,259,815	332,170	146,534	2,738,519	

Attachment D

CL&P RSP INVESTMENT BY PLANT ACCOUNT AT 12-31-10

		Data		
Plant A/C	Work Order Inservice Year	Sum of Gross Plant2	Sum of Accum Depr2	Sum of Net Plant2
350	2004	423,777.17	36,822.06	386,955.11
	2005	2,350,091.18	176,243.10	2,173,848.08
	2006	11,244,274.29	377,631.35	10,866,642.94
	2007	10,947,554.21	538,766.68	10,408,787.53
	2008	1,057,463.60	38,404.79	1,019,058.81
	2009	1,320,946.74	29,437.46	1,291,509.28
	2010	605,307.25	4,601.58	600,705.67
350 Total		27,949,414.44	1,201,907.02	26,747,507.42
352	2004	1,161,779.38	187,425.41	974,353.97
	2005	4,433,913.69	614,593.20	3,819,320.49
	2006	7,262,782.25	836,949.37	6,425,832.88
	2007	3,435,859.13	313,126.16	3,122,732.96
	2008	9,333,288.95	618,240.98	8,715,047.97
352 Total		25,627,623.40	2,570,335.12	23,057,288.28
353	2004	51,301,239.25	5,924,477.96	45,376,761.29
	2005	66,592,309.94	6,706,468.25	59,885,841.69
	2006	68,197,034.42	5,795,992.31	62,401,042.11
	2007	54,850,940.53	3,743,213.03	51,107,727.50
	2008	187,586,397.66	9,448,464.23	178,137,933.43
	2009	370,039.18	11,560.69	358,478.49
353 Total		428,897,960.97	31,630,176.46	397,267,784.51
354	2008	75,434.70	4,551.85	70,882.85
354 Total		75,434.70	4,551.85	70,882.85
355	2004	233,478.02	56,088.98	177,389.04
	2005	2,569,188.47	518,393.86	2,050,794.61
	2006	17,448,331.55	2,861,562.14	14,586,769.41
	2007	75,986,465.27	9,644,699.13	66,341,766.14
	2008	99,177,139.00	8,971,391.44	90,205,747.56
355 Total		195,414,602.31	22,052,135.55	173,362,466.76
356	2004	163,768.35	30,915.17	132,853.18
	2005	2,669,039.42	419,908.98	2,249,130.44
	2006	5,483,973.68	695,331.34	4,788,642.34
	2007	36,339,794.53	3,534,705.32	32,805,089.21
	2008	60,372,039.40	4,153,721.88	56,218,317.51
356 Total		105,028,615.37	8,834,582.70	96,194,032.68
357	2004	1,058,908.61	84,217.69	974,690.92
	2005	16,291,589.29	1,174,049.47	15,117,539.81
	2006	20,432,422.46	1,297,582.44	19,134,840.02
	2007	0.00	0.00	0.00
	2008	355,375,201.39	14,856,289.72	340,518,911.67
357 Total		393,158,121.75	17,412,139.32	375,745,982.43
358	2004	1,180,509.94	40,705.66	1,139,804.28
	2005	9,150,257.10	303,674.71	8,846,582.39
	2006	67,217,115.44	2,117,246.37	65,099,869.08
	2007	0.00	0.00	0.00
	2008	303,278,988.04	10,235,837.61	293,043,150.43
358 Total		380,826,870.52	12,697,464.35	368,129,406.17
359	2006	3,875,097.81	254,679.86	3,620,417.95
	2008	18,098,811.26	675,860.81	17,422,950.45
359 Total		21,973,909.07	930,540.67	21,043,368.40
Grand Total		1,578,952,552.53	97,333,833.04	1,481,618,719.50

Attachment D1

PSNH RSP INVESTMENT BY PLANT ACCOUNT AT 12-31-10

		Data		
Plant A/C	Year	Sum of Gross Plant2	Sum of Accum Depr2	Sum of Net Plant2
350	2007	3,413.51	0.00	3,413.51
350 Total		3,413.51	0.00	3,413.51
352	2006	401,937.67	31,133.86	370,803.81
	2007	416,869.30	25,143.05	391,726.25
	2008	8,203,611.74	353,760.57	7,849,851.17
352 Total		9,022,418.71	410,037.48	8,612,381.23
353	2004	14,069,510.91	1,609,473.54	12,460,037.38
	2005	5,432,171.26	536,172.64	4,895,998.63
	2006	11,522,533.57	950,856.52	10,571,677.05
	2007	14,237,722.52	936,642.68	13,301,079.84
	2008	36,195,544.04	1,750,663.00	34,444,881.04
353 Total		81,457,482.31	5,783,808.38	75,673,673.93
355	2004	1,684,384.08	281,507.20	1,402,876.88
	2005	145,459.57	20,526.58	124,932.99
	2006	3,140,266.96	362,250.72	2,778,016.24
	2007	16,838,977.22	1,512,472.22	15,326,505.00
	2008	3,905,123.42	251,455.93	3,653,667.49
355 Total		25,714,211.25	2,428,212.65	23,285,998.60
356	2004	741,149.36	127,622.44	613,526.92
	2005	38,143.60	5,409.43	32,734.17
	2006	1,566,678.99	176,991.76	1,389,687.23
	2007	4,126,890.94	353,707.59	3,773,183.35
	2008	1,669,751.37	100,201.97	1,569,549.40
356 Total		8,142,614.26	763,933.19	7,378,681.07
Grand Total		124,340,140.04	9,385,991.70	114,954,148.34

Attachment D2

WMECO RSP INVESTMENT BY PLANT ACCOUNT AT 12-31-10				
		Data		
Plant A/C	Year	Sum of Gross Plant2	Sum of Accum Depr2	Sum of Net Plant2
353	2004	3,551,718.67	460,996.04	3,090,722.63
	2005	3,004,443.99	335,158.31	2,669,285.68
	2006	4,654,941.92	431,499.06	4,223,442.86
	2008	1,095,892.69	58,182.98	1,037,709.71
Grand Total		12,306,997.27	1,285,836.39	11,021,160.88

Attachment E

CL+P ADVANCED TECHNOLOGY INVESTMENT AT 12-31-10

Work Order Description	Plant A/c	Work Order Inservice Year	Gross Plant	Accum Depr	Net Plant
BRIDGEPORT 2006 AQUIRED EASEMENTSSEG 3 MN345K	35002	2006	551,702.94	34,551.81	517,151.13
FAIRFIELD 2006 AQUIRED EASEMENTS MN345KV SEG4	35002	2006	1,276,433.81	79,939.94	1,196,493.87
WESTPORT 2006 EASEMENTS AQUIRED MN345KV SEG4	35002	2006	1,471,790.40	92,174.64	1,379,615.76
NORWALK 2006 EASEMENTS AQUIRED MN345KV SEG 4	35002	2006	871,657.40	54,589.78	817,067.62
MN 345KV SEG1 BESECK SWITCH STATION	35389	2007	214,782.79	14,657.50	200,125.29
MN 345KV SEG 3 ROW EASEMENTS	35002	2007	154,082.53	7,665.59	146,416.94
MN 345KV SEG 3 ROW EASEMENTS	35002	2007	318,714.78	15,856.03	302,858.75
MN 345KV SEG 4 ROW EASEMENTS	35002	2007	832,242.54	41,403.97	790,838.57
MN 345KV SEG 4 ROW EASEMENTS	35002	2007	1,969,149.47	97,964.97	1,871,184.50
MN 345KV SEG 4 ROW EASEMENTS	35002	2007	1,100,725.15	54,760.96	1,045,964.19
MN 345KV SEGMENT 2 EAST DEVON S/S-115KV WORK	35389	2008	242,919.72	12,235.52	230,684.20
MN 345KV SEGMENT 2 EAST DEVON S/S-345KV WORK	35389	2008	155,527.35	7,833.69	147,693.65
MN 345KV SEGMENT 2 EAST DEVON S/S-AUTOS	35389	2008	131,699.72	6,633.53	125,066.19
MN 345KV SEGMENT 2 EAST DEVON S/S-AUTOS	35389	2008	167,348.48	8,429.11	158,919.38
MN 345KV SEGMENT 3 EAST DEVON TO SINGER	357	2008	29,727,273.87	1,242,734.42	28,484,539.46
MN 345KV SEGMENT 3 EAST DEVON TO SINGER	358	2008	20,921,098.89	539,587.15	20,381,511.74
MN 345KV SEGMENT 4 SINGER TO NORWALK	357	2008	212,287,754.46	8,874,587.70	203,413,166.76
MN 345KV SEGMENT 4 SINGER TO NORWALK	358	2008	138,565,519.43	3,573,816.76	134,991,702.66
MN 345KV SEGMENT 4 NORWALK SS	35389	2008	132,143.37	6,655.87	125,487.50
MN 345KV SEGMENT 4 NORWALK SS	35389	2008	88,092.22	4,437.08	83,655.14
MN 345KV SEG 4 ROW EASEMENT LL 543.01 WESTPOR	35002	2008	21,606.96	784.72	20,822.24
MN 345KV SEGMENT 4 NORWALK SS	35389	2008	276,774.02	13,940.72	262,833.31
MN 345KV SEGMENT 4 NORWALK SS_SHUNT REACTORS	35389	2008	7,967,373.18	401,305.43	7,566,067.75
MN 345KV SEG 3 ROW EASEMENT LL 430_BRIDGEPORT	35002	2009	170,502.97	3,799.68	166,703.29
MN 345KV SEG 3 ROW EASEMENT LL 430.01 BRIDGEP	35002	2009	53,105.96	1,183.47	51,922.49
MN 345KV SEG 3 ROW EASEMENT LL 442 & 443	35002	2009	54,542.04	1,215.48	53,326.56
MN 345KV SEG 3 ROW EASEMENT LL 451.02 B'PORT	35002	2009	14,681.15	327.17	14,353.98
MN 345KV SEG 4 ROW EASEMENT LL 421 FAIRFIELD	35002	2009	172,772.58	3,850.26	168,922.32
MN 345KV SEG 4 ROW EASEMENT LL 520 WESTPORT	35002	2009	70,682.00	1,575.16	69,106.84
MN 345KV SEG 3 ROW EASEMENT LL 444 BRIDGEPORT	35002	2010	19,780.99	150.38	19,630.61
MN 345KV SEG 4 ROW EASEMENT LL 518 WESTPORT	35002	2010	146,494.92	1,113.66	145,381.26
MN 345KV SEG 3 ROW EASEMENT LL 437 BRIDGEPORT	35002	2010	93,861.12	713.54	93,147.58
MN 345KV SEG 4 ROW EASEMENT LL 523 WESTPORT	35002	2010	97,312.09	739.77	96,572.32
MN 345KV SEG 4 ROW EASEMENT LL 541 WESTPORT	35002	2010	91,794.06	697.82	91,096.24
MN 345KV SEG 4 ROW EASEMENT LL 543.01 WESTPOR	35002	2010	156,064.07	1,186.41	154,877.66
			420,588,007.44	15,203,099.69	405,384,907.75

Attachment F

CL&P NEEWS Investment Balances as of 12-31-10

Work Order Description	G/L A/C	Plant A/C	Work Order In Service	Gross Plant	Accum Depr	Net Plant
LAND PURCHASE FOR UNCASVILLE CAP BANKS	10601	350	2010	196,154.99	0.00	196,154.99
REBUILD #353 345KV LINE FROM KLEEN TO WRJ	10601	355	2010	1,422,589.19	26,006.37	1,396,582.82
REBUILD #353 345KV LINE FROM KLEEN TO WRJ	10601	356	2010	389,701.82	5,500.10	384,201.72
310/368 LINE SEPARATION	10601	353	2010	7,115,485.70	76,708.42	7,038,777.28
310/368 LINE REBUILD/SEPARATION	10601	356	2010	490,638.64	6,924.68	483,713.96
310/368 LINE REBUILD/SEPARATION	10601	356	2010	2,166,806.03	30,581.43	2,136,224.60
BUNKER HILL 1272 TERMINAL UPRATES	10601	353	2010	319,742.83	3,446.98	316,295.85
NEEWS PURCHASE LAND IN LEBANON, CT- LL 30000.02	10601	350	2010	419,089.05	0.00	419,089.05
				12,520,208.25	149,167.98	12,371,040.27

Attachment G

NU Transmission 2011 PTF In-Service Forecast

($ X 1000)

Company	ISO-NE RSP Project ID	Project Title	Estimated PTF In-Service
CL&P	(a)	Middletown - Norwalk 345-kV project	$ 1,922
CL&P	(b)	NEEWS Projects	$ 3,468
CL&P	N/A	115-kV Relay replacements	$ 10,586
CL&P	N/A	CL&P OPGW Projects	$ 5,569
CL&P	N/A	115KV & 345KV Hollow Core Insulator Project	$ 11,782
CL&P	N/A	Obsolete Equipment Replacement Projects	$ 4,424
CL&P	N/A	SCADA Replacement Program	$ 5,683
CL&P	N/A	CAP & PIN Insulator Replacement Projects	$ 450
CL&P	N/A	CL&P Annuals	$ 5,269
CL&P	1147 & 1148	Waterside 22M-Install 1BRKR and Ring BUS	$ 4,760
CL&P	N/A	CL&P-HVAC in Trans Control Rooms	$ 2,143
CL&P	N/A	CL&P-Trans Vehicle Purchases-2011	$ 2,120
CL&P	N/A	Lines 1760/1876 Repl Polymer Insl	$ 1,885
CL&P	N/A	Mystic-SS Expansion-T Portion	$ 1,212
CL&P	N/A	Transformer LTC's & Oil Filtration Sys	$ 1,164
CL&P	N/A	Upgrade LTC at Southington and Card S/S	$ 1,111
CL&P	N/A	Other CL&P PTF Projects	$ 12,264
CL&P	N/A	CL&P Sale to CTMEEC	$ (45,068)
CL&P	N/A	NEEWS CWIP-CT	$ 137,010
		Total CL&P	**167,754**
PSNH	(c)	Deerfield 2nd Autotransformer	$ 29,505
PSNH	1182	Thornton Site (Formerly Thorton Ferry S/S)	$ 60
PSNH	1143	Littleton 115kV Substation Project	$ 7,672
PSNH	N/A	PSNH OPGW Projects	$ 3,530
PSNH	N/A	115kV & 345kV Hollow Core Insulator Repl	$ 2,644
PSNH	N/A	Obsolete Equipment Replacement Projects	$ 2,123
PSNH	N/A	115kV & 345kV Relay Replacements	$ 3,041
PSNH	N/A	Cap & Pin Insulator Replacement Projects	$ 83
PSNH	N/A	PSNH Annuals	$ 2,247
PSNH	1219	Oak Hill SS Capacitor Banks Installation	$ 4,090
PSNH	N/A	Webster-BKR Replacement L176, F139, M127	$ 1,406
PSNH	N/A	Other PSNH PTF Projects	$ 3,699
		Total PSNH	**$ 60,100**
WMECO	(b)	NEEWS Projects	$ 22,979
WMECO	N/A	SCADA Replacement Program	$ 2,209
WMECO	N/A	WMECO 1421 Line Structure Replacement	$ 10,964
WMECO	N/A	WMECO 1371 Line Structure Replacement	$ 2,045
WMECO	N/A	WMECO 1512 Line Structure Replacement	$ 7,532
WMECO	N/A	Line 354 - 345kV Reconstruction	$ 6,402
WMECO	N/A	WMECO Annuals	$ 1,124
WMECO	N/A	Other WMECO PTF Projects	$ 3,637
WMECO	N/A	NEEWS CWIP-MA	$ 250,362
		Total WMECO	**$ 307,254**

Total NU PTF Plant In-Service	**147,736**
Total NU CWIP	**387,372**
Total Northeast Utilities	**535,108**

(a) In-Service RSP Project

(b) There are multiple RSP numbers associated with the NEEWS projects in both CT and MA

(c) There are multiple RSP numbers associated with the Deerfield project (277, 1137, 1130, 1139 & 1140)

Northeast Utilities Systems Companies
Capitalization
Calendar Year 2010- Year End

Line No.	**Long Term Debt**	**CL&P Year End**	**PSNH Year End**	**WMECO Year End**	**Reference**
1	Outstanding Bonds (A/C 221 & 224)	2,341,030,943	837,285,000	343,800,000	**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)	4,486,894	920,162	709,628	**FF1 page 112 ln. 23**
4	Debt Expense (A/C 181)	17,603,959	7,451,646	2,655,343	**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)**	**2,318,940,090**	**828,913,192**	**340,435,029**	
7	**Total LTD (Beginning of Year / End of Year Average)**	**2,318,017,566**	**828,461,641**	**293,396,569**	**(Line 6 + prior YE capitalization) / 2**
8	Annual Amort of Prem Disc. & Exp. (A/C 428 minus A/C 429)	1,834,590	1,132,516	312,410	**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 207)	134,738,676	40,745,025	18,090,592	**FF1 pg 257 ln. 33 + pg 256.1, ln 13 fn (PCRB Interest)**
11	**Total Annual Cost (line 8-9+10)**	136,573,266	**41,877,541**	**18,403,002**	
12	**LTD Cost of Capital (line 11/7)**	**5.89%**	**5.05%**	**6.27%**	
	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)	354,504	-	-	**FF1 page 112 ln. 10**
17	**Net Proceeds (Year End) line 13+14-15-16**	**116,665,523**	**-**	**-**	
18	**Net Proceeds (BOY / EOY Average)**	**116,640,201**			**(Line 17 + prior YE Net Proceeds) / 2**
19	Issue Expense Amortization (A/C 214)	50,644	-	-	**FF1 page 112 ln. 10 (diff. in py & cy)**
20	Dividend (A/C 437)	6,101,610	-	-	**FF1 page 118 ln. 25**
21	**Annual Expense (line 19+20)**	6,152,254	**-**	**-**	
22	**PS Cost of Capital (line 21/18)**	**5.27%**	**-**	**-**	
23	Proprietary Capital	2,513,674,238	926,447,441	357,583,697	**FF1 page 112 ln. 16**
24	**Common Equity (line 22-17)**	2,397,008,715	926,447,441	357,583,697	

2010 AFUDC Equity Amortization in Depreciation

PRE-97

	a	b	c	d	e	f	g
	Transmission	PTF Allocator	Transmission PTF level (a*b)	General Transmission	PTF Allocator	General PTF level (d*e)	Total at PTF level (c+f)
CL&P	2,210,088.0	14.9945%	331,392	73,410	14.9945%	11,007	342,399
PSNH	170,791.0	22.0385%	37,640	17,616	22.0385%	3,882	41,522
WMECO	36,259.0	33.6189%	12,190	108	33.6189%	36	12,226
	2,417,138		381,222	91,134		14,925	396,147

2010 AFUDC Equity Amortization in Depreciation

POST-96

	a	b	c	d	e	f	g
	Transmission	PTF Allocator	Transmission PTF level (a*b)	General Transmission	PTF Allocator	General PTF level (d*e)	Total at PTF level (c+f)
CL&P	2,210,088	73.5507%	1,625,535	73,410	73.5507%	53,994	1,679,529
PSNH	170,791	71.0897%	121,415	17,616	71.0897%	12,523	133,938
WMECO	36,259	55.6346%	20,173	108	55.6346%	60	20,233
	2,417,138		1,767,123	91,134		66,577	1,833,700

Note: This worksheet represents the "C" component of the Federal and State Income Tax Formula.

Attachment J

Connecticut Light and Power Company

2010 PTF Activity

Plant Account	Beginning Balance 1-1-10	Additions	Retirements	Adjustments/ Transfers	Ending Balance 12-31-10
350	68,450,591.48	880,123.79	(181.24)	(571,826.46)	68,758,707.57
352	39,508,346.51	(443,959.07)	(49,453.15)	(70,282.22)	38,944,652.06
353	700,486,640.91	18,638,842.72	(3,704,000.02)	(2,624,263.37)	712,797,220.24
354	27,134,366.96	(7,402.33)	0.00	(77,754.90)	27,049,209.73
355	349,291,739.58	9,105,953.91	(657,873.28)	(17,647,798.28)	340,092,021.93
356	211,534,674.05	7,254,528.02	(72,629.12)	1,020,870.99	219,737,443.94
357	392,795,832.01	8,955,733.40		(6,316,777.90)	395,434,787.51
358	386,529,437.21	4,823,974.13	(4,963.09)	(4,160,319.34)	387,188,128.91
359	29,307,957.82	521,789.75	(43,789.01)	183,870.39	29,969,828.95
361	9,448,797.99	738,463.71	(14,815.91)	(286,723.76)	9,885,722.03
362	24,222,393.36	334,558.24	(108,023.68)	(673,595.97)	23,775,331.95
Grand Total	2,238,710,777.88	50,802,606.27	(4,655,728.50)	(31,224,600.82)	2,253,633,054.83

Attachment J1

Public Service Company of New Hampshire					
2010 PTF Activity					
	Beginning				Ending
	Balance			Adjustments/	Balance
Plant Account	1-1-10	Additions	Retirements	Transfers	12-31-10
350	15,123,601.40	2,389,401.71	(4,804.28)	30,537.12	17,538,735.95
352	17,518,113.88	(1,622,046.44)	(5,217.79)	(189,909.08)	15,700,940.57
353	198,182,511.64	11,799,292.90	(1,983,517.08)	(335,604.02)	207,662,683.44
354	9,705,137.54				9,705,137.54
355	79,009,646.45	7,711,322.71	(136,414.94)	(224,014.02)	86,360,540.20
356	49,686,200.51	3,587,484.77	(150,857.53)		53,122,827.75
357	0.00				0.00
358	0.00				0.00
359	710,796.72	6,469.45		(12,115.19)	705,150.98
361	4,766,787.27	624,040.60	(1,391.47)	(1,055.26)	5,388,381.14
362	5,428,168.00	90,554.89	(78,195.16)	(4,236.81)	5,436,290.92
Grand Total	380,130,963.41	24,586,520.59	(2,360,398.25)	(736,397.26)	401,620,688.47

Attachment J2

Western Massachusetts Electric Company

2010 PTF Activity

Plant Account	Beginning Balance 1-1-10	Additions	Retirements	Adjustments/ Transfers	Ending Balance 12-31-10
350	9,527,737.03		(1,915.47)	30,728.45	9,556,550.01
352	3,294,567.82	(1,478,675.03)	(9,833.81)	(20,015.39)	1,786,043.59
353	75,030,304.59	8,267,270.65	(522,107.39)	(14,726.86)	82,760,740.99
354	1,149,771.59				1,149,771.59
355	29,752,141.07	15,895,198.31	(363,094.74)		45,284,244.64
356	28,715,134.17	(4,704,515.65)	(695,391.79)		23,315,226.73
357	31,742.27				31,742.27
358	1,197,865.05				1,197,865.05
359	101,324.98	5,885.39			107,210.37
361	2,168,852.07	314,740.28	(14,180.47)	111,222.19	2,580,634.07
362	5,004,262.38		(23,992.85)	330,494.51	5,310,764.04
Grand Total	155,973,703.02	18,299,903.95	(1,630,516.52)	437,702.90	173,080,793.35

Attachment K

Recalculation of PTF Revenue Requirements Annual True-up
Resulting from ISO-NE's final determination of the
Transmission Cost Allocation ("TCA") in Schedule 12C of ISO-NE OATT applications for Middletown-Norwalk and Glenbrook

Original Total PTF Revenue Requirement True-up

		Annual True-up Pre-97	Annual True-up Post-96	Total True-up Amount	Reference
1	**2006**	$ (760,010)	$ (2,106,745)	$ (2,866,755)	
2	**2007**	$ 7,051,603	$ 18,874,081	$ 25,925,684	
3	**2008**	$ (2,182,641)	$ 61,024,513	$ 58,841,872	
4	**2009**	$ 4,275,134	$ 7,805,586	$ 12,080,720	
5	**Total (Sum of lines 1 to 4)**	$ 8,384,086	$ 85,597,435	$ 93,981,521	

May 18, 2011 Revised Total PTF Revenue Requirement True-up

		Annual True-up Pre-97	Annual True-up Post-96	Total True-up Amount	Reference
6	**2006 (line 1+11)**	$ (922,706)	$ (2,327,329)	$ (3,250,035)	Exhibit 1 ATRR
7	**2007 (line 2+12)**	$ 6,194,345	$ 15,599,490	$ 21,793,835	Exhibit 2 ATRR
8	**2008 (line 3+13)**	$ (2,960,347)	$ 49,140,917	$ 46,180,570	Exhibit 3 ATRR
9	**2009 (line 4+14)**	$ 3,594,887	$ (1,113,684)	$ 2,481,203	Exhibit 4 ATRR
10	**Total (Sum of lines 6 to 9)**	$ 5,906,179	$ 61,299,394	$ 67,205,573	

Incremental Refund of PTF Revenue Requirements as a result of the Final ISO-NE Determinations

		Annual True-up Pre-97	Annual True-up Post-96	Total True-up Amount	Reference
11	**2006**	$ (162,696)	$ (220,584)	$ (383,280)	Exhibit 1 w/s 1D-1
12	**2007**	$ (857,258)	$ (3,274,591)	$ (4,131,849)	Exhibit 2 w/s 1D
13	**2008**	$ (777,706)	$ (11,883,596)	$ (12,661,302)	Exhibit 3 w/s 1E
14	**2009**	$ (680,247)	$ (8,919,270)	$ (9,599,517)	Exhibit 4 w/s 1E
15	**Total (Sum of lines 11 to 14)**	$ (2,477,907)	$ (24,298,041)	$ (26,775,948)	

Note: Amounts include interest calculated through May 31, 2011.

Exhibit 1

Adjusted 2006 PTF Revenue Requirements To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects

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

Submitted on: 18-May-11

Revenue Requirements for (year): June 1, 2007 - May 31, 2008

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

	Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I =	-	(a)	-	(g)
Total of Attachment F - Section J - Support Revenue	-	(b)	-	(h)
Total of Attachment F - Section K - Support Expense	-	(c)	-	(i)
Total of Attachment F - Section (L through O)	-	(d)	-	(j)
Sub Total - Sum (A through I) - J + K + (L through O)	-	(e)=(a)-(b)+(c)+(d)	-	(k)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	-	(f)	-	(l)
Annual True-up (per Attachment C to Attachment F Implementation Rule)	($922,706)	(m)	$ (2,327,329)	(n)
Adjusted Sub Total (Sub Total + True-up)		(o) = (e)+(f)+(m)		(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)				(q) = (o) + (p)

Note: This revised PTO Annual Transmission Revenue Requirements sheet dated May 18, 2011 only reflects the revised annual true-up as a result of ISO-NE Final Schedule 12C determinations for the Middletown-Norwalk and Glenbrook Cables Projects. (see Attachment K for the incremental refund)

Worksheet 1A

Northeast Utilities System Companies'
Adjusted Annual Revenue Requirements of PTF Facilities for costs in 2006
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
for Rates billed June 1, 2006 - September 3, 2006
Pre-1997 - at 10.9%

Line No.		Attachment F Reference	CL&P	PSNH	WMECO	HWP	HP&E	Total	Reference
I.	INVESTMENT BASE	*Section:*							
1	Transmission Plant	(A)(1)(a)	403,642,354	95,419,451	63,684,238	986,885	1,311,855	565,044,783	w/s 3A line 1
2	General Plant	(A)(1)(b)	6,012,637	5,320,887	1,767,647	-	-	13,101,171	w/s 3A line 2
3	Plant Held For Future Use	(A)(1)(c)	863,073	1,532,170	69,503	-	-	2,464,746	w/s 3A line 4
4	Total Plant (Lines 1+2+3)		410,518,064	102,272,508	65,521,388	986,885	1,311,855	580,610,700	
5	Accumulated Depreciation	(A)(1)(d)	121,037,200	37,286,334	25,161,630	945,347	1,062,361	185,492,872	w/s 3A line 7
6	Accumulated Deferred Income Taxes	(A)(1)(e)	28,200,996	10,282,147	10,611,567	-	29,438	49,124,148	w/s 3A line 10
7	Loss On Reacquired Debt	(A)(1)(f)	1,471,217	540,194	52,981	-	-	2,064,392	w/s 3A line 11
8	Other Regulatory Assets	(A)(1)(g)	2,738,139	371,951	5,018,803	-	-	8,128,893	w/s 3A line 15
9	Net Investment (Line 4-5-6+7+8)		265,489,224	55,616,172	34,819,975	41,538	220,056	356,186,965	
10	Prepayments	(A)(1)(h)	4,945,386	572,627	2,649,842	-	-	8,167,855	w/s 3A line 16
11	Materials & Supplies	(A)(1)(i)	5,859,011	1,303,342	115,521	(11)	-	7,277,863	w/s 3A line 17
12	Cash Working Capital	(A)(1)(j)	2,152,309	693,721	468,019	(3,623)	1,532	3,311,958	w/s 3A line 24
13	Total Investment Base (Line 9+10+11+12)		278,445,930	58,185,862	38,053,357	37,904	221,588	374,944,641	
II.	REVENUE REQUIREMENTS								
14	Investment Return and Income Taxes	(A)	34,664,374	6,742,682	4,530,385	7,023	39,742	45,984,206	w/s 2A -10.9%
15	Depreciation Expense	(B)	7,725,270	2,077,719	1,155,909	16,407	19,918	10,995,223	w/s 4A line 3
16	Amortization of Loss on Reacquired Debt	(C)	95,212	42,631	1,349	-	-	139,192	w/s 4A line 4
17	Investment Tax Credit	(D)	(278,666)	(15,748)	(37,176)	-	-	(331,590)	w/s 4A line 5
18	Property Tax Expense	(E)	3,199,222	2,121,204	1,116,244	26,870	34,610	6,498,150	w/s 4A line 8
19	Payroll Tax Expense	(F)	85,698	35,976	18,739	-	-	140,413	w/s 4A line 19
20	Operation & Maintenance Expense	(G)	8,407,971	2,659,781	1,816,069	5,323	482	12,889,626	w/s 4A line 17
21	Administrative & General Expense	(H)	8,010,934	2,889,983	1,470,430	(49,343)	11,772	12,333,775	w/s 4A line 18
22	Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	-	-	
23	Transmission Support Revenue	(J)	(1,452,162)	(2,752,410)	-	-	-	(4,204,572)	
24	Transmission Support Expense	(K)	2,251,729	1,294,102	457,656	15,036	-	4,018,523	
25	Transmission Related Expense from Generators	(L)	-	-	-	-	-	-	
26	Transmission Related Taxes and Fees Charge	(M)	858,285	22,112	22,661	-	2,683	905,740	Attachment B line 14
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(309,122)	(81,263)	(57,780)	(667)	(488)	(449,320)	Attachment C line 11
28	Transmission Rents Received from Electric Property	(O)	(4,765,355)	(1,318,730)	(269,699)	-	-	(6,353,784)	
29	Total Revenue Requirements (Line 14 thru 28)		58,493,389	13,718,039	10,224,787	20,649	108,718	2,565,583	

Worksheet 1A-1

Northeast Utilities System Companies'
Adjusted Annual Revenue Requirements of PTF Facilities for costs in 2006
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
for Rates billed September 3, 2006 - October 31, 2006
Pre-1997 - at 11%

Line No.		Attachment F Reference *Section:*	CL&P	PSNH	WMECO	HWP	HP&E	Total	Reference
I.	INVESTMENT BASE								
1	Transmission Plant	(A)(1)(a)	403,642,354	95,419,451	63,684,238	986,885	1,311,855	565,044,783	w/s 3A line 1
2	General Plant	(A)(1)(b)	6,012,637	5,320,887	1,767,647	-	-	13,101,171	w/s 3A line 2
3	Plant Held For Future Use	(A)(1)(c)	863,073	1,532,170	69,503	-	-	2,464,746	w/s 3A line 4
4	Total Plant (Lines 1+2+3)		410,518,064	102,272,508	65,521,388	986,885	1,311,855	580,610,700	
5	Accumulated Depreciation	(A)(1)(d)	121,037,200	37,286,334	25,161,630	945,347	1,062,361	185,492,872	w/s 3A line 7
6	Accumulated Deferred Income Taxes	(A)(1)(e)	28,200,996	10,282,147	10,611,567	-	29,438	49,124,148	w/s 3A line 10
7	Loss On Reacquired Debt	(A)(1)(f)	1,471,217	540,194	52,981	-	-	2,064,392	w/s 3A line 11
8	Other Regulatory Assets	(A)(1)(g)	2,738,139	371,951	5,018,803	-	-	8,128,893	w/s 3A line 15
9	Net Investment (Line 4-5-6+7+8)		265,489,224	55,616,172	34,819,975	41,538	220,056	356,186,965	
10	Prepayments	(A)(1)(h)	4,945,386	572,627	2,649,842	-	-	8,167,855	w/s 3A line 16
11	Materials & Supplies	(A)(1)(i)	5,859,011	1,303,342	115,521	(11)	-	7,277,863	w/s 3A line 17
12	Cash Working Capital	(A)(1)(j)	2,152,309	693,721	468,019	(3,623)	1,532	3,311,958	w/s 3A line 24
13	Total Investment Base (Line 9+10+11+12)		278,445,930	58,185,862	38,053,357	37,904	221,588	374,944,641	
II.	REVENUE REQUIREMENTS								
14	Investment Return and Income Taxes	(A)	34,899,745	6,791,599	4,561,692	7,088	40,106	46,300,230	w/s 2A -11%
15	Depreciation Expense	(B)	7,725,270	2,077,719	1,155,909	16,407	19,918	10,995,223	w/s 4A line 3
16	Amortization of Loss on Reacquired Debt	(C)	95,212	42,631	1,349	-	-	139,192	w/s 4A line 4
17	Investment Tax Credit	(D)	(278,666)	(15,748)	(37,176)	-	-	(331,590)	w/s 4A line 5
18	Property Tax Expense	(E)	3,199,222	2,121,204	1,116,244	26,870	34,610	6,498,150	w/s 4A line 8
19	Payroll Tax Expense	(F)	85,698	35,976	18,739	-	-	140,413	w/s 4A line 19
20	Operation & Maintenance Expense	(G)	8,407,971	2,659,781	1,816,069	5,323	482	12,889,626	w/s 4A line 17
21	Administrative & General Expense	(H)	8,010,934	2,889,983	1,470,430	(49,343)	11,772	12,333,775	w/s 4A line 18
22	Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	-	-	
23	Transmission Support Revenue	(J)	(1,452,162)	(2,752,410)	-	-	-	(4,204,572)	
24	Transmission Support Expense	(K)	2,251,729	1,294,102	457,656	15,036	-	4,018,523	
25	Transmission Related Expense from Generators	(L)	-	-	-	-	-	-	
26	Transmission Related Taxes and Fees Charge	(M)	858,285	22,112	22,661	-	2,683	905,740	Attachment B line 14
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(309,122)	(81,263)	(57,780)	(667)	(488)	(449,320)	Attachment C line 11
28	Transmission Rents Received from Electric Property	(O)	(4,765,355)	(1,318,730)	(269,699)	-	-	(6,353,784)	
29	Total Revenue Requirements (Line 14 thru 28)		58,728,760	13,766,956	10,256,094	20,714	109,082	82,881,606	

Worksheet 1A-2

Northeast Utilities System Companies'
Adjusted Annual Revenue Requirements of PTF Facilities for costs in 2006
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
for rates billed beginning November 1, 2006
Pre-1997 - at 11.64%

Line No.		Attachment F Reference *Section:*	CL&P	PSNH	WMECO	HWP	HP&E	Total	Reference
	I. INVESTMENT BASE								
1	Transmission Plant	(A)(1)(a)	403,642,354	95,419,451	63,684,238	986,885	1,311,855	565,044,783	w/s 3A line 1
2	General Plant	(A)(1)(b)	6,012,637	5,320,887	1,767,647	-	-	13,101,171	w/s 3A line 2
3	Plant Held For Future Use	(A)(1)(c)	863,073	1,532,170	69,503	-	-	2,464,746	w/s 3A line 4
4	Total Plant (Lines 1+2+3)		410,518,064	102,272,508	65,521,388	986,885	1,311,855	580,610,700	
5	Accumulated Depreciation	(A)(1)(d)	121,037,200	37,286,334	25,161,630	945,347	1,062,361	185,492,872	w/s 3A line 7
6	Accumulated Deferred Income Taxes	(A)(1)(e)	28,200,996	10,282,147	10,611,567	-	29,438	49,124,148	w/s 3A line 10
7	Loss On Reacquired Debt	(A)(1)(f)	1,471,217	540,194	52,981	-	-	2,064,392	w/s 3A line 11
8	Other Regulatory Assets	(A)(1)(g)	2,738,139	371,951	5,018,803	-	-	8,128,893	w/s 3A line 15
9	Net Investment (Line 4-5-6+7+8)		265,489,224	55,616,172	34,819,975	41,538	220,056	356,186,965	
10	Prepayments	(A)(1)(h)	4,945,386	572,627	2,649,842	-	-	8,167,855	w/s 3A line 16
11	Materials & Supplies	(A)(1)(i)	5,859,011	1,303,342	115,521	(11)	-	7,277,863	w/s 3A line 17
12	Cash Working Capital	(A)(1)(j)	2,152,309	693,721	468,019	(3,623)	1,532	3,311,958	w/s 3A line 24
13	Total Investment Base (Line 9+10+11+12)		278,445,930	58,185,862	38,053,357	37,904	221,588	374,944,641	
	II. REVENUE REQUIREMENTS								
14	Investment Return and Income Taxes	(A)	36,311,995	7,094,876	4,768,318	7,500	42,440	48,225,129	w/s 2A - 11.64%
15	Depreciation Expense	(B)	7,725,270	2,077,719	1,155,909	16,407	19,918	10,995,223	w/s 4A line 3
16	Amortization of Loss on Reacquired Debt	(C)	95,212	42,631	1,349	-	-	139,192	w/s 4A line 4
17	Investment Tax Credit	(D)	(278,666)	(15,748)	(37,176)	-	-	(331,590)	w/s 4A line 5
18	Property Tax Expense	(E)	3,199,222	2,121,204	1,116,244	26,870	34,610	6,498,150	w/s 4A line 8
19	Payroll Tax Expense	(F)	85,698	35,976	18,739	-	-	140,413	w/s 4A line 19
20	Operation & Maintenance Expense	(G)	8,407,971	2,659,781	1,816,069	5,323	482	12,889,626	w/s 4A line 17
21	Administrative & General Expense	(H)	8,010,934	2,889,983	1,470,430	(49,343)	11,772	12,333,775	w/s 4A line 18
22	Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	-	-	
23	Transmission Support Revenue	(J)	(1,452,162)	(2,752,410)	-	-	-	(4,204,572)	
24	Transmission Support Expense	(K)	2,251,729	1,294,102	457,656	15,036	-	4,018,523	
25	Transmission Related Expense from Generators	(L)	-	-	-	-	-	-	
26	Transmission Related Taxes and Fees Charge	(M)	858,285	22,112	22,661	-	2,683	905,740	Attachment B line 14
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(309,122)	(81,263)	(57,780)	(667)	(488)	(449,320)	Attachment C line 11
28	Transmission Rents Received from Electric Property	(O)	(4,765,355)	(1,318,730)	(269,699)	-	-	(6,353,784)	
29	Total Revenue Requirements (Line 14 thru 28)		60,141,010	14,070,233	10,462,719	21,126	111,416	84,806,504	

Worksheet 1B

Northeast Utilities System Companies'
Adjusted Annual Revenue Requirements of PTF Facilities for costs in 2006
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
for Rates billed June 1, 2006 - September 3, 2006
Post - 1996 - at 10.9%

Line No.		Attachment F Reference *Section:*	CL&P	PSNH	WMECO	HWP	HP&E	Total	Reference
	I. INVESTMENT BASE								
1	Transmission Plant	(A)(1)(a)	466,493,001	100,588,941	38,254,753	152,566	50,788	605,540,049	w/s 3A line 1
2	General Plant	(A)(1)(b)	6,948,865	5,609,146	1,061,815	-	-	13,619,826	w/s 3A line 2
3	Plant Held For Future Use	(A)(1)(c)	997,462	1,615,176	41,750	-	-	2,654,388	w/s 3A line 4
4	Total Plant (Lines 1+2+3)		474,439,328	107,813,263	39,358,318	152,566	50,788	621,814,263	
5	Accumulated Depreciation	(A)(1)(d)	139,883,891	39,306,317	15,114,445	146,144	41,129	194,491,926	w/s 3A line 7
6	Accumulated Deferred Income Taxes	(A)(1)(e)	32,592,170	10,839,182	6,374,306	-	1,140	49,806,798	w/s 3A line 10
7	Loss On Reacquired Debt	(A)(1)(f)	1,700,301	569,459	31,826	-	-	2,301,586	w/s 3A line 11
8	Other Regulatory Assets	(A)(1)(g)	3,164,494	392,101	3,014,765	-	-	6,571,360	w/s 3A line 15
9	Net Investment (Line 4-5-6+7+8)		306,828,062	58,629,324	20,916,158	6,422	8,519	386,388,485	
10	Prepayments	(A)(1)(h)	5,715,432	603,649	1,591,745	-	-	7,910,826	w/s 3A line 16
11	Materials & Supplies	(A)(1)(i)	6,771,317	1,373,950	69,393	(2)	-	8,214,658	w/s 3A line 17
12	Cash Working Capital	(A)(1)(j)	2,371,936	731,303	246,773	(851)	55	3,349,216	w/s 3A line 24
13	Total Investment Base (Line 9+10+11+12)		321,686,747	61,338,226	22,824,069	5,569	8,574	405,863,185	
	II. REVENUE REQUIREMENTS								
14	Investment Return and Income Taxes	(A)	40,047,523	7,107,984	2,717,272	1,032	1,538	49,875,349	w/s 2A -10.9%
15	Depreciation Expense	(B)	8,928,171	2,190,279	694,347	2,536	771	11,816,104	w/s 4A line 3
16	Amortization of Loss on Reacquired Debt	(C)	110,038	44,940	810	-	-	155,788	w/s 4A line 4
17	Investment Tax Credit	(D)	(322,057)	(16,601)	(22,332)	-	-	(360,990)	w/s 4A line 5
18	Property Tax Expense	(E)	3,697,372	2,236,120	670,521	4,154	1,340	6,609,507	w/s 4A line 8
19	Payroll Tax Expense	(F)	99,042	37,925	11,256	-	-	148,223	w/s 4A line 19
20	Operation & Maintenance Expense	(G)	9,717,174	2,803,873	1,090,903	823	19	13,612,792	w/s 4A line 17
21	Administrative & General Expense	(H)	9,258,315	3,046,548	883,278	(7,628)	419	13,180,932	w/s 4A line 18
22	Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	-	-	
23	Transmission Related Expense from Generators	(L)	-	-	-	-	-	-	
24	Transmission Related Taxes and Fees Charge	(M)	991,928	23,310	13,677	-	104	1,029,019	Attachment B line 16
25	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(357,232)	(85,671)	(34,712)	(103)	(19)	(477,737)	Attachment C line 12
26	Total Revenue Requirements (Line 14 thru 25)		72,170,274	17,388,706	6,025,020	814	4,172	95,588,987	

Worksheet 1B-1

Northeast Utilities System Companies'
Adjusted Annual Revenue Requirements of PTF Facilities for costs in 2006
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
for Rates billed September 3, 2006 - October 31, 2006
Post - 1996 - at 11%

		Attachment F Reference	CL&P	PSNH	WMECO	HWP	HP&E	Total	Reference
Line No.	I. INVESTMENT BASE	*Section:*							
1	Transmission Plant	(A)(1)(a)	466,493,001	100,588,941	38,254,753	152,566	50,788	605,540,049	w/s 3A line 1
2	General Plant	(A)(1)(b)	6,948,865	5,609,146	1,061,815	-	-	13,619,826	w/s 3A line 2
3	Plant Held For Future Use	(A)(1)(c)	997,462	1,615,176	41,750	-	-	2,654,388	w/s 3A line 4
4	Total Plant (Lines 1+2+3)		474,439,328	107,813,263	39,358,318	152,566	50,788	621,814,263	
5	Accumulated Depreciation	(A)(1)(d)	139,883,891	39,306,317	15,114,445	146,144	41,129	194,491,926	w/s 3A line 7
6	Accumulated Deferred Income Taxes	(A)(1)(e)	32,592,170	10,839,182	6,374,306	-	1,140	49,806,798	w/s 3A line 10
7	Loss On Reacquired Debt	(A)(1)(f)	1,700,301	569,459	31,826	-	-	2,301,586	w/s 3A line 11
8	Other Regulatory Assets	(A)(1)(g)	3,164,494	392,101	3,014,765	-	-	6,571,360	w/s 3A line 15
9	Net Investment (Line 4-5-6+7+8)		306,828,062	58,629,324	20,916,158	6,422	8,519	386,388,485	
10	Prepayments	(A)(1)(h)	5,715,432	603,649	1,591,745	-	-	7,910,826	w/s 3A line 16
11	Materials & Supplies	(A)(1)(i)	6,771,317	1,373,950	69,393	(2)	-	8,214,658	w/s 3A line 17
12	Cash Working Capital	(A)(1)(j)	2,371,936	731,303	246,773	(851)	55	3,349,216	w/s 3A line 24
13	Total Investment Base (Line 9+10+11+12)		321,686,747	61,338,226	22,824,069	5,569	8,574	405,863,185	
	II. REVENUE REQUIREMENTS								
14	Investment Return and Income Taxes	(A)	40,319,445	7,159,551	2,736,049	1,041	1,552	50,217,638	w/s 2A - 11%
15	Depreciation Expense	(B)	8,928,171	2,190,279	694,347	2,536	771	11,816,104	w/s 4A line 3
16	Amortization of Loss on Reacquired Debt	(C)	110,038	44,940	810	-	-	155,788	w/s 4A line 4
17	Investment Tax Credit	(D)	(322,057)	(16,601)	(22,332)	-	-	(360,990)	w/s 4A line 5
18	Property Tax Expense	(E)	3,697,372	2,236,120	670,521	4,154	1,340	6,609,507	w/s 4A line 8
19	Payroll Tax Expense	(F)	99,042	37,925	11,256	-	-	148,223	w/s 4A line 19
20	Operation & Maintenance Expense	(G)	9,717,174	2,803,873	1,090,903	823	19	13,612,792	w/s 4A line 17
21	Administrative & General Expense	(H)	9,258,315	3,046,548	883,278	(7,628)	419	13,180,932	w/s 4A line 18
22	Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	-	-	
23	Transmission Related Expense from Generators	(L)	-	-	-	-	-	-	
24	Transmission Related Taxes and Fees Charge	(M)	991,928	23,310	13,677	-	104	1,029,019	Attachment B line 16
25	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(357,232)	(85,671)	(34,712)	(103)	(19)	(477,737)	Attachment C line 12
26	Total Revenue Requirements (Line 14 thru 25)		72,442,196	17,440,273	6,043,797	823	4,186	95,931,276	

Northeast Utilities System Companies'
Adjusted Annual Revenue Requirements of PTF Facilities for costs in 2006
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
for rates billed beginning November 1, 2006
Post - 1996 - at 11.64%

Line No.		Attachment F Reference *Section:*	CL&P	PSNH	WMECO	HWP	HP&E	Total	Reference
	I. INVESTMENT BASE								
1	Transmission Plant	(A)(1)(a)	466,493,001	100,588,941	38,254,753	152,566	50,788	605,540,049	w/s 3A line 1
2	General Plant	(A)(1)(b)	6,948,865	5,609,146	1,061,815	-	-	13,619,826	w/s 3A line 2
3	Plant Held For Future Use	(A)(1)(c)	997,462	1,615,176	41,750	-	-	2,654,388	w/s 3A line 4
4	Total Plant (Lines 1+2+3)		474,439,328	107,813,263	39,358,318	152,566	50,788	621,814,263	
5	Accumulated Depreciation	(A)(1)(d)	139,883,891	39,306,317	15,114,445	146,144	41,129	194,491,926	w/s 3A line 7
6	Accumulated Deferred Income Taxes	(A)(1)(e)	32,592,170	10,839,182	6,374,306	-	1,140	49,806,798	w/s 3A line 10
7	Loss On Reacquired Debt	(A)(1)(f)	1,700,301	569,459	31,826	-	-	2,301,586	w/s 3A line 11
8	Other Regulatory Assets	(A)(1)(g)	3,164,494	392,101	3,014,765	-	-	6,571,360	w/s 3A line 15
9	Net Investment (Line 4-5-6+7+8)		306,828,062	58,629,324	20,916,158	6,422	8,519	386,388,485	
10	Prepayments	(A)(1)(h)	5,715,432	603,649	1,591,745	-	-	7,910,826	w/s 3A line 16
11	Materials & Supplies	(A)(1)(i)	6,771,317	1,373,950	69,393	(2)	-	8,214,658	w/s 3A line 17
12	Cash Working Capital	(A)(1)(j)	2,371,936	731,303	246,773	(851)	55	3,349,216	w/s 3A line 24
13	Total Investment Base (Line 9+10+11+12)		321,686,747	61,338,226	22,824,069	5,569	8,574	405,863,185	
	II. REVENUE REQUIREMENTS								
14	Investment Return and Income Taxes	(A)	41,951,008	7,479,258	2,859,981	1,102	1,642	52,292,991	w/s 2A - 11.64%
15	Depreciation Expense	(B)	8,928,171	2,190,279	694,347	2,536	771	11,816,104	w/s 4A line 3
16	Amortization of Loss on Reacquired Debt	(C)	110,038	44,940	810	-	-	155,788	w/s 4A line 4
17	Investment Tax Credit	(D)	(322,057)	(16,601)	(22,332)	-	-	(360,990)	w/s 4A line 5
18	Property Tax Expense	(E)	3,697,372	2,236,120	670,521	4,154	1,340	6,609,507	w/s 4A line 8
19	Payroll Tax Expense	(F)	99,042	37,925	11,256	-	-	148,223	w/s 4A line 19
20	Operation & Maintenance Expense	(G)	9,717,174	2,803,873	1,090,903	823	19	13,612,792	w/s 4A line 17
21	Administrative & General Expense	(H)	9,258,315	3,046,548	883,278	(7,628)	419	13,180,932	w/s 4A line 18
22	Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	-	-	
23	Transmission Related Expense from Generators	(L)	-	-	-	-	-	-	
24	Transmission Related Taxes and Fees Charge	(M)	991,928	23,310	13,677	-	104	1,029,019	Attachment B line 16
25	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(357,232)	(85,671)	(34,712)	(103)	(19)	(477,737)	Attachment C line 12
26	Total Revenue Requirements (Line 14 thru 25)		74,073,759	17,759,980	6,167,730	884	4,276	98,006,629	

Northeast Utilities System Companies'
Adjusted Annual Revenue Requirements of post-2003 PTF Incremental Return for costs in 2006
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
for Rates billed June 1, 2007 - May 31, 2008

Line		CL&P	PSNH	WMECO	Total	Reference
	I. INVESTMENT BASE					
1	Transmission Plant	$342,224,646	$ 38,342,537	$ 9,050,455	$ 389,617,638	Attachment A1
2	Accumulated Depreciation	$ 6,902,833	$ 1,130,296	$ 272,618	$ 8,305,747	↓
3	Accumulated Deferred Income Taxes	$ 13,615,065	$ 1,774,010	$ 416,517	$ 15,805,592	
4	Net Investment (Line 1-2-3)	$321,706,748	$ 35,438,231	$ 8,361,320	$ 365,506,299	
	II. INCREMENTAL RETURN					
5	Incremental Revenue Requirements	$ 2,556,250	$ 286,008	$ 70,166	$ 2,912,424	w/s 2A

Northeast Utilities System Companies'
Adjusted Transmission Revenue Requirements of PTF Facilities
Year 2006 True-up
Pre-97 and Post-96
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects

Line	I.	ANNUAL TRUE-UP	Pre-97		
			Billed	Actual	Difference
1		6/1/06 - 8/31/06	82,686,174	82,565,583	
2		x 3/12 months	x 3/12	x 3/12	
3		Prorated Amount	20,671,543	20,641,396	
4		9/1/06 - 10/31/06	83,002,985	82,881,606	
5		x 2/12 months	x 2/12	x 2/12	
6		Prorated Amount	13,833,831	13,813,601	
7		11/1/06 - 5/31/07	84,932,778	84,806,504	
8		x 7/12 months	x 7/12	x 7/12	
9		Prorated Amount	49,544,121	49,470,461	
10		**Total Annual True-up Amount (line 3+6+9)**	**84,049,495**	**83,925,458**	**124,037**

		ANNUAL TRUE-UP	Post-96		
			Billed	Actual	Difference
11		6/1/06 - 8/31/06	98,665,146	98,501,411	
12		x 3/12 months	x 3/12	x 3/12	
13		Prorated Amount	24,666,286	24,625,353	
14		9/1/06 - 10/31/06	96,096,082	95,931,276	
15		x 2/12 months	x 2/12	x 2/12	
16		Prorated Amount	16,016,014	15,988,546	
17		11/1/06 - 5/31/07	$101,090,084	100,919,053	
18		x 7/12 months	x 7/12	x 7/12	
19		Prorated Amount	58,969,216	58,869,448	
20		**Total Annual True-up Amount (line 13+16+19)**	**99,651,516**	**99,483,347**	**168,169**

Worksheet 1D-1

Northeast Utilities Service Companies'
FERC Interest Calculation associated with Surcharge / (Refund)
Adjusted Transmission Revenue Requirements of PTF Facilities
PRE-97 / Post-96
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects

	Surcharge / (Refund)	
Pre	$ (124,037)	w/s 1D line 10
Post	$ (168,169)	w/s 1D line 20

	Balance		FERC Monthly Interest Rate	Interest	
Initial Billing Period	Pre 97	Post 96		Pre 97	Post 96
June 2006	$ (124,037)	$ (168,169)	0.60%	$ (744)	$ (1,009)
July 2006	$ (124,781)	$ (169,178)	0.66%	$ (824)	$ (1,117)
August 2006	$ (124,781)	$ (169,178)	0.66%	$ (824)	$ (1,117)
September 2006	$ (124,781)	$ (169,178)	0.64%	$ (799)	$ (1,083)
October 2006	$ (127,227)	$ (172,494)	0.69%	$ (878)	$ (1,190)
November 2006	$ (127,227)	$ (172,494)	0.67%	$ (852)	$ (1,156)
December 2006	$ (127,227)	$ (172,494)	0.69%	$ (878)	$ (1,190)
January 2007	$ (129,835)	$ (176,030)	0.70%	$ (909)	$ (1,232)
February 2007	$ (129,835)	$ (176,030)	0.63%	$ (818)	$ (1,109)
March 2007	$ (129,835)	$ (176,030)	0.70%	$ (909)	$ (1,232)
April 2007	$ (132,471)	$ (179,604)	0.68%	$ (901)	$ (1,221)
May 2007	$ (132,471)	$ (179,604)	0.70%	$ (927)	$ (1,257)
June 2007	$ (132,471)	$ (179,604)	0.68%	$ (901)	$ (1,221)
July 2007	$ (135,200)	$ (183,304)	0.70%	$ (946)	$ (1,283)
August 2007	$ (135,200)	$ (183,304)	0.70%	$ (946)	$ (1,283)
September 2007	$ (135,200)	$ (183,304)	0.68%	$ (919)	$ (1,246)
October 2007	$ (138,012)	$ (187,116)	0.70%	$ (966)	$ (1,310)
November 2007	$ (138,012)	$ (187,116)	0.68%	$ (938)	$ (1,272)
December 2007	$ (138,012)	$ (187,116)	0.70%	$ (966)	$ (1,310)
January 2008	$ (140,883)	$ (191,008)	0.66%	$ (930)	$ (1,261)
February 2008	$ (140,883)	$ (191,008)	0.62%	$ (873)	$ (1,184)
March 2008	$ (140,883)	$ (191,008)	0.66%	$ (930)	$ (1,261)
April 2008	$ (143,616)	$ (194,714)	0.56%	$ (804)	$ (1,090)
May 2008	$ (143,616)	$ (194,714)	0.57%	$ (819)	$ (1,110)
June 2008	$ (143,616)	$ (194,714)	0.56%	$ (804)	$ (1,090)
July 2008	$ (146,043)	$ (198,005)	0.45%	$ (657)	$ (891)
August 2008	$ (146,043)	$ (198,005)	0.45%	$ (657)	$ (891)
September 2008	$ (146,043)	$ (198,005)	0.44%	$ (643)	$ (871)
October 2008	$ (148,000)	$ (200,658)	0.42%	$ (622)	$ (843)
November 2008	$ (148,000)	$ (200,658)	0.41%	$ (607)	$ (823)
December 2008	$ (148,000)	$ (200,658)	0.42%	$ (622)	$ (843)

Worksheet 1D-1

Initial Billing Period	Balance		FERC Monthly Interest Rate	Interest	
	Pre 97	Post 96		Pre 97	Post 96
January 2009	$ (149,850)	$ (203,166)	0.38%	$ (569)	$ (772)
February 2009	$ (149,850)	$ (203,166)	0.34%	$ (509)	$ (691)
March 2009	$ (149,850)	$ (203,166)	0.38%	$ (569)	$ (772)
April 2009	$ (151,498)	$ (205,401)	0.28%	$ (424)	$ (575)
May 2009	$ (151,498)	$ (205,401)	0.29%	$ (439)	$ (596)
June 2009	$ (151,498)	$ (205,401)	0.28%	$ (424)	$ (575)
July 2009	$ (152,786)	$ (207,147)	0.28%	$ (428)	$ (580)
August 2009	$ (152,786)	$ (207,147)	0.28%	$ (428)	$ (580)
September 2009	$ (152,786)	$ (207,147)	0.27%	$ (413)	$ (559)
October 2009	$ (154,054)	$ (208,866)	0.28%	$ (431)	$ (585)
November 2009	$ (154,054)	$ (208,866)	0.27%	$ (416)	$ (564)
December 2009	$ (154,054)	$ (208,866)	0.28%	$ (431)	$ (585)
January 2010	$ (155,333)	$ (210,600)	0.28%	$ (435)	$ (590)
February 2010	$ (155,333)	$ (210,600)	0.25%	$ (388)	$ (526)
March 2010	$ (155,333)	$ (210,600)	0.28%	$ (435)	$ (590)
April 2010	$ (156,591)	$ (212,306)	0.27%	$ (423)	$ (573)
May 2010	$ (156,591)	$ (212,306)	0.28%	$ (438)	$ (594)
June 2010	$ (156,591)	$ (212,306)	0.27%	$ (423)	$ (573)
July 2010	$ (157,875)	$ (214,047)	0.28%	$ (442)	$ (599)
August 2010	$ (157,875)	$ (214,047)	0.28%	$ (442)	$ (599)
September 2010	$ (157,875)	$ (214,047)	0.27%	$ (426)	$ (578)
October 2010	$ (159,185)	$ (215,823)	0.28%	$ (446)	$ (604)
November 2010	$ (159,185)	$ (215,823)	0.27%	$ (430)	$ (583)
December 2010	$ (159,185)	$ (215,823)	0.28%	$ (446)	$ (604)
January 2011	$ (160,507)	$ (217,614)	0.28%	$ (449)	$ (609)
February 2011	$ (160,507)	$ (217,614)	0.25%	$ (401)	$ (544)
March 2011	$ (160,507)	$ (217,614)	0.28%	$ (449)	$ (609)
April 2011	$ (161,807)	$ (219,377)	0.27%	$ (437)	$ (592)
May 2011	$ (161,807)	$ (219,377)	0.28%	$ (453)	$ (614)
	Total Surcharge/(Refund)			**$ (162,697)**	**$ (220,584)**
			Interest	Principal	Total (check)
			$ (38,659)	$ (124,037)	$ (162,697)
			$ (52,414)	$ (168,169)	$ (220,584)
			(91,074)	(292,207)	(383,280)

Worksheet 2A
10.9%

Connecticut Light & Power Company (CL&P)
Adjusted Investment Return and Income Taxes - 2006
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
PRE-97
for Rates billed June 1, 2006 - September 3, 2006

	CAPITALIZATION 12/31/2006	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 1,274,544,002	48.25%	6.96%	3.36%	
PREFERRED STOCK	$ 116,373,012	4.41%	4.94%	0.22%	0.22%
COMMON EQUITY	$ 1,250,856,603	47.34%	10.90%	5.16%	5.16%
TOTAL INVESTMENT RETURN	$ 2,641,773,617	100.00%		8.74%	5.38%

Cost of Capital Rate=

(a) Weighted Cost of Capital	=	0.08740											
				PTF Inv.		Eq. AFUDC							
(b) Federal Income Tax	= (	R.O.E. +	(	(Tax Credit	+	of Deprec. Exp.	) /	PTF Inv. Base)		x	Federal Income Tax Rate)		
						(1 - Federal Income Tax Rate)							
	=	5.3800%	+(	(278,666)	+	253,309	) /	278,445,930	)	x	35.00%)		
					(	1	-	0.35)					
	=	0.0289202											
				PTF Inv.		Eq. AFUDC							
(c) State Income Tax	=	R.O.E. +	(	(Tax Credit	+	of Deprec. Exp.	) /	PTF Inv. Base)		+	Federal Income Tax)*State Income Tax Rate		
						(1 - State Income tax Rate)							
	=	0.0538	+(	(278,666)	+	253,309	) /	278,445,930	)	+	0.0289202	)*	0.09
					(	1	-	0.09)					
	=	0.0081721											
(a)+(b)+(c) Cost of Capital Rate	=	0.1244923											

	Pre-1997 PTF	
INVESTMENT BASE	278,445,930	From Worksheet 1
x Cost of Capital Rate	0.1244923	
= Investment Return and Income Taxes	$ 34,664,374	To Worksheet 1

Connecticut Light & Power Company (CL&P)
Adjusted Investment Return and Income Taxes - 2006
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
POST-96
for Rates billed June 1, 2006 - September 3, 2006

	CAPITALIZATION 12/31/2006	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 1,274,544,002	48.25%	6.96%	3.36%	
PREFERRED STOCK	$ 116,373,012	4.41%	4.94%	0.22%	0.22%
COMMON EQUITY	$ 1,250,856,603	47.34%	10.90%	5.16%	5.16%
TOTAL INVESTMENT RETURN	$ 2,641,773,617	100.00%		8.74%	5.38%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.08740

(b) Federal Income Tax

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

$$= \frac{5.3800\% \;+(\;(322{,}057) + 292{,}752\;)\;/\;321{,}686{,}747\;)\;\;x\;\;35.00\%\;)}{(\;1\;-\;0.35\;)}$$

= 0.0289202

(c) State Income Tax

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

$$= \frac{0.0538 \;+(\;(322{,}057) + 292{,}752\;)\;/\;321{,}686{,}747\;)\; + \;0.0289202\;)^{*}\;\;0.09}{(\;1\;-\;0.09\;)}$$

= 0.0081721

(a)+(b)+(c) Cost of Capital Rate = 0.1244923

	Post - 1996 PTF	
INVESTMENT BASE	321,686,747	From Worksheet 1
x Cost of Capital Rate	0.1244923	
= Investment Return and Income Taxes	$ 40,047,523	To Worksheet 1

Connecticut Light & Power Company (CL&P)
Adjusted Investment Return and Income Taxes - 2006
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
PRE-97
for Rates billed September 3, 2006 - October 31, 2006

	CAPITALIZATION 12/31/2006	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 1,274,544,002	48.25%	6.96%	3.36%	
PREFERRED STOCK	$ 116,373,012	4.41%	4.94%	0.22%	0.22%
COMMON EQUITY	$ 1,250,856,603	47.34%	11.00%	5.21%	5.21%
TOTAL INVESTMENT RETURN	$ 2,641,773,617	100.00%		8.79%	5.43%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.08790

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

= 5.4300% +((278,666) + 253,309) / 278,445,930) x 35.00%)
(1 - 0.35)

= 0.0291894

(c) State Income Tax = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate
(1 - State Income tax Rate)

= 0.0543 +((278,666) + 253,309) / 278,445,930) + 0.0291894)* 0.09
(1 - 0.09)

= 0.0082482

(a)+(b)+(c) Cost of Capital Rate = 0.1253376

	Pre-1997 PTF	
INVESTMENT BASE	278,445,930	From Worksheet 1
x Cost of Capital Rate	0.1253376	
= Investment Return and Income Taxes	$ 34,899,745	To Worksheet 1

Connecticut Light & Power Company (CL&P)
Adjusted Investment Return and Income Taxes - 2006
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
POST-96
for Rates billed September 3, 2006 - October 31, 2006

		CAPITALIZATION 12/31/2006	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	1,274,544,002	48.25%	6.96%	3.36%	
PREFERRED STOCK	$	116,373,012	4.41%	4.94%	0.22%	0.22%
COMMON EQUITY	$	1,250,856,603	47.34%	11.00%	5.21%	5.21%
TOTAL INVESTMENT RETURN	$	2,641,773,617	100.00%		8.79%	5.43%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.08790

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

= 5.4300% +((322,057) + 292,752) / 321,686,747) x 35.00%)
(1 - 0.35)

= 0.0291894

(c) State Income Tax = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate
(1 - State Income tax Rate)

= 0.0543 +((322,057) + 292,752) / 321,686,747) + 0.0291894)* 0.09
(1 - 0.09)

= 0.0082482

(a)+(b)+(c) Cost of Capital Rate = 0.1253376

		Post - 1996 PTF	
INVESTMENT BASE		321,686,747	From Worksheet 1
x Cost of Capital Rate		0.1253376	
= Investment Return and Income Taxes	$	40,319,445	To Worksheet 1

Worksheet 2A
11.64%

Connecticut Light & Power Company (CL&P)
Adjusted Investment Return and Income Taxes - 2006
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
PRE-97
for rates billed beginning November 1, 2006

	CAPITALIZATION 12/31/2006	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 1,274,544,002	48.25%	6.96%	3.36%	
PREFERRED STOCK	$ 116,373,012	4.41%	4.94%	0.22%	0.22%
COMMON EQUITY	$ 1,250,856,603	47.34%	11.64%	5.51%	5.51%
TOTAL INVESTMENT RETURN	$ 2,641,773,617	100.00%		9.09%	5.73%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.09090

				PTF Inv.		Eq. AFUDC				
(b) Federal Income Tax	= (	R.O.E. +	(	(Tax Credit	+	of Deprec. Exp.	) /	PTF Inv. Base)	x	Federal Income Tax Rate)
						(1 - Federal Income Tax Rate)				
	=	5.7300%	+(	(278,666)	+	253,309	) /	278,445,930)	x	35.00%)
						(1	-	0.35)		
	=	0.0308048								

				PTF Inv.		Eq. AFUDC						
(c) State Income Tax	=	R.O.E. +	(	(Tax Credit	+	of Deprec. Exp.	) /	PTF Inv. Base)	+	Federal Income Tax)*State Income Tax Rate		
						(1 - State Income tax Rate)						
	=	0.0573	+(	(278,666)	+	253,309	) /	278,445,930)	+	0.0308048	)*	0.09
						(1	-	0.09)				
	=	0.0087047										

(a)+(b)+(c) Cost of Capital Rate = 0.1304095

	Pre-1997 PTF	
INVESTMENT BASE	278,445,930	From Worksheet 1
x Cost of Capital Rate	0.1304095	
= Investment Return and Income Taxes	$ 36,311,995	To Worksheet 1

Worksheet 2A
11.64%

Connecticut Light & Power Company (CL&P)
Adjusted Investment Return and Income Taxes - 2006
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
POST-96
for rates billed beginning November 1, 2006

	CAPITALIZATION 12/31/2006	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 1,274,544,002	48.25%	6.96%	3.36%	
PREFERRED STOCK	$ 116,373,012	4.41%	4.94%	0.22%	0.22%
COMMON EQUITY	$ 1,250,856,603	47.34%	11.64%	5.51%	5.51%
TOTAL INVESTMENT RETURN	$ 2,641,773,617	100.00%		9.09%	5.73%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.09090

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

= 5.7300% +((322,057) + 292,752) / 321,686,747) x 35.00%)
(1 - 0.35)

= 0.0308048

(c) State Income Tax = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate
(1 - State Income tax Rate)

= 0.0573 +((322,057) + 292,752) / 321,686,747) + 0.0308048)* 0.09
(1 - 0.09)

= 0.0087047

(a)+(b)+(c) Cost of Capital Rate = 13.0410%

	Post - 1996 PTF	
INVESTMENT BASE	321,686,747	From Worksheet 1
x Cost of Capital Rate	0.1304095	
= Investment Return and Income Taxes	$ 41,951,008	To Worksheet 1

Worksheet 2A Post 03

The Connecticut Light & Power Company
Adjusted Investment Return and Income Taxes - 2006
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Post 2003
Incremental ROE Adder for RSP Projects

		CAPITALIZATION 12/31/2006	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	1,274,544,002	48.25%	#N/A		
PREFERRED STOCK		116,373,012	4.41%			
COMMON EQUITY		1,250,856,603	47.34%	1.00%	0.47%	0.47%
TOTAL INVESTMENT RETURN	$	2,641,773,617	100.00%		0.47%	0.47%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0047

				PTF Inv.		Eq. AFUDC					
(b) Federal Income Tax	=	(	R.O.E. +	((Tax Credit	+	of Deprec. Exp.	) /	PTF Inv. Base)	x	Federal Income Tax Rate	)
		(	1						-	Federal Income Tax Rate	)
	=	(	0.0047	+ ((0	+	0	) /	321,706,748)	x	0.35	)
		(	1						-	0.35	)
	=		0.0025308								
				PTF Inv.		Eq. AFUDC					
(c) State Income Tax	=	(	R.O.E. +	((Tax Credit	+	of Deprec. Exp.	) /	PTF Inv. Base)	+	Federal Income Tax	)* State Income Tax Rate
		(	1						-	State Income Tax Rate	)
	=	(	0.0047	+ ((0	+	0	) /	321,706,748)	+	0.0025308	)* 0.09
		(	1						-	0.09	)
	=		0.0007151								

(a)+(b)+(c) Cost of Capital Rate = 0.0079459

		(post-2003 PTF)	
INVESTMENT BASE	$	321,706,748	From Worksheet 1a
x Cost of Capital Rate		0.0079459	
= Investment Return and Income Taxes		2,556,250	To Worksheet 1a

Connecticut Light & Power Company (CL&P)
Adjusted Rate Base Items
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Calendar Year 2006

					PRE-97 PTF		POST-96 PTF		
Line No.		(1) Total	(2) Wage/Plant Allocation Factors (a)	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	(6) PTF Allocation Factor (b)	(7) = (3)*(6) PTF Allocated	Reference
	Transmission Plant								
1	Transmission Plant					403,642,354		466,493,001	Attachment A
2	General Plant	15,933,341		15,933,341	37.7362%	6,012,637	43.6121%	6,948,865	FF1 page 204 ln. 96, footnote
3	Total (line 1+2)			15,933,341		409,654,991		473,441,866	
4	Transmission Plant Held for Future Use	2,287,123 (c)		2,287,123	37.7362%	863,073	43.6121%	997,462	(c)
	Transmission Accumulated Depreciation (b)								
5	Transmission Accum. Depreciation	312,573,200		312,573,200	37.7362%	117,953,248	43.6121%	136,319,737	FF1 page 219 ln. 25
6	General Plant Accum.Depreciation	8,172,396		8,172,396	37.7362%	3,083,952	43.6121%	3,564,154	FF1 page 219 ln. 28, footnote
7	Total (line 5+6)			320,745,596		121,037,200		139,883,891	
	Transmission Accumulated Deferred Taxes								
8	Accumulated Deferred Taxes (281 to 283)	(97,125,992)		(97,125,992)	37.7362%	(36,651,659)	43.6121%	(42,358,685)	FF1 page 274 ln. 9 FN & 276 ln. 19 footnote
9	Accumulated Deferred Taxes (190)	22,394,050		22,394,050	37.7362%	8,450,663	43.6121%	9,766,515	
10	Total (line 8+9)			(74,731,942)		(28,200,996)		(32,592,170)	
11	Transmission loss on Reacquired Debt	3,898,690		3,898,690	37.7362%	1,471,217	43.6121%	1,700,301	FF1 page 110 ln. 81, footnote
	Other Regulatory Assets								
12	FAS 106	-		-	37.7362%	-	43.6121%	-	FF1 page 232
13	FAS 109	12,963,000		12,963,000	37.7362%	4,891,744	43.6121%	5,653,437	FF1 page 232 ln. 10, footnote
14	Other Regulatory Liabilities (254.DK)	(5,707,000)		(5,707,000)	37.7362%	(2,153,605)	43.6121%	(2,488,943)	FF1 page 278 ln. 5, footnote
15	Total (line 12+13+14)			7,256,000		2,738,139		3,164,494	
16	Transmission Prepayments (165)	13,105,151		13,105,151	37.7362%	4,945,386	43.6121%	5,715,432	FF1 page 110 ln. 57, footnote
17	Transmission Materials and Supplies	15,526,235		15,526,235	37.7362%	5,859,011	43.6121%	6,771,317	FF1 page 227 ln. 8
18	Cash Working Capital								
19	Operation & Maintenance Expense					8,407,971		9,717,174	w/s 4A, Line 17
20	Administrative & General Expense					8,010,934		9,258,315	w/s 4A, Line 18
21	Transmission Support Expense					799,567		-	w/s 7
22	Subtotal (line 19+20+21)					17,218,472		18,975,489	
23						0.125		0.125	x 45 / 360
24	Total (line 22 * line 23)					2,152,309		2,371,936	

(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	4,845,127	FF1 page 214
Less Royal Oaks Bypass	2,558,004	
	2,287,123	

Worksheet 4A

Connecticut Light & Power Company (CL&P)
Adjusted Expense Items
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Calendar Year 2006

					PRE-97 PTF		POST-96 PTF		
		(1)	(2)	(3) = (1)*(2)	(4)	(5) = (3)*(4)	(6)	(7) = (3)*(6)	
Line No.		Total	Wage/Plant Allocation Factors (a)	Transmission Allocated	PTF Allocation Factor (b)	Pre-97 PTF Allocated	PTF Allocation Factor	Post-96 PTF Allocated	Reference
	Depreciation Expense								
1	Transmission Depreciation	19,271,511		19,271,511	37.7362%	7,272,336	43.6121%	8,404,711	FF1 page 336 ln. 7
2	General Depreciation	1,200,264		1,200,264	37.7362%	452,934	43.6121%	523,460	FF1 page 336 ln. 10, footnote
3	Total (line 1+2)			20,471,775		7,725,270		8,928,171	
4	Amortization of Loss on Reacquired Debt	252,310		252,310	37.7362%	95,212	43.6121%	110,038	FF1 page 114, ln. 64, footnote
5	Amortization of Investment Tax Credits	738,459		738,459	37.7362%	278,666	43.6121%	322,057	FF1 page 266 ln. 8, footnote - difference of PY-CY
	Property Taxes								
6	Transmission Property Taxes	8,288,817		8,288,817	37.7362%	3,127,885	43.6121%	3,614,927	FF1 page 262 ln. 25i, footnote
7	General Property Taxes (c)	189,041		189,041	37.7362%	71,337	43.6121%	82,445	
8	Total (line 6+7)			8,477,858		3,199,222		3,697,372	
	Transmission Operation and Maintenance								
9	Operation and Maintenance	285,644,464		285,644,464	37.7362%	107,791,366	43.6121%	124,575,549	FF1 page 321 ln. 112
10	Transmission of Electricity by Others - #565	253,199,813		253,199,813	37.7362%	95,547,988	43.6121%	110,425,756	FF1 page 321 ln. 96
11	Load Dispatching - #561	1,533,011		1,533,011	37.7362%	578,500	43.6121%	668,578	FF1 page 321 ln. 84
12	Account 561.1	1,610,176		1,610,176	37.7362%	607,619	43.6121%	702,232	FF1 page 321 ln. 85
13	Account 561.2	2,850,730		2,850,730	37.7362%	1,075,757	43.6121%	1,243,263	FF1 page 321 ln. 86
14	Account 561.3	1,235,101		1,235,101	37.7362%	466,080	43.6121%	538,653	FF1 page 321 ln. 87
15	Account 561.4	2,934,719		2,934,719	37.7362%	1,107,451	43.6121%	1,279,893	FF1 page 321 ln. 88
16	**Station Expenses & Rents - #562 / #567	-		-		-		-	
17	O&M less lines 10 through 16	22,280,914		22,280,914	37.7362%	8,407,971	43.6121%	9,717,174	
	Transmission Administrative and General								
18	Administrative and General	21,228,777		21,228,777	37.7362%	8,010,934	43.6121%	9,258,315	FF1 page 320 ln. 197, footnote
19	*Payroll Tax Expense*	*227,098*		227,098	37.7362%	85,698	43.6121%	99,042	
	Federal Unemployment	2,259							FF1 page 262 ln. 3i, footnotes
	FICA	165,463							FF1 page 262 ln. 5i, footnote
	Medicare	46,038							FF1 page 262 ln. 9i, footnote
	CT Unemployment	13,136							FF1 page 262 ln. 15i, footnote
	MA Unemployment	31							FF1 page 262.1 ln. 13i, footnote
	MA Universal Health	41							FF1 page 262.1 ln. 17i, footnote
	NH Unemployment	77							FF1 page 262 footnote
	NJ Unemployment	-							FF1 page 262 ln. 32i, footnote
	DC Unemployment	9							FF1 page 262 ln. 33i, footnote
	FL Unemployment	4							FF1 page 262.1 ln. 3i, footnote
	GA Unemployment	-							FF1 page 262 footnote
	NY Unemployment	40							FF1 page 262.1 ln. 9i, footnote
	Total	227,098	To Line 19						

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

(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.

Worksheet 5A

Northeast Utilities System Companies
Adjusted Allocation Factors
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Calendar Year 2006
PRE-1997

Line No.	**PTF Transmission Plant Allocation Factor**	CL&P	PSNH	WMECO	HWP	HP&E	TOTAL	Reference
1	PTF Transmission Investment	403,642,354	95,419,451	63,684,238	986,885	1,311,855	565,044,783	w/s 3A line 1
2	Total Transmission Investment	1,069,641,270	220,365,800	118,389,665	1,188,911	1,427,437	1,411,013,083	FF1 page 206-207 ln 58
3	Percent Allocation (Line 1/Line 2)	37.7362%	43.3005%	53.7921%	83.0075%	91.9028%	40.0453%	
	Transmission Wages and Salaries Allocation Factor							
4	Direct Transmission Wages and Salaries	5,494,992	1,667,036	964,188	-	-	8,126,216	FF1 page 354 ln 21
5	Affiliated Company Transmission Wages and Salaries	6,891,657	1,432,816	885,580	-	-	9,210,053	w/s 6 line 15
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	12,386,649	3,099,852	1,849,768	-	-	17,336,269	
7	Total Wages and Salaries	97,235,431	65,256,321	18,345,322	-	-	180,837,074	FF1 page 354 ln 28
8	Administrative and General Wages and Salaries	10,037,206	9,585,028	1,956,464	-	-	21,578,698	FF1 page 354 ln 27
9	Affiliated Company Wages and Salaries less A&G	58,112,043	12,661,465	9,837,693	122,206	-	80,733,407	w/s 6 line 30
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	145,310,268	68,332,758	26,226,551	122,206	-	239,991,783	
11	Percent Allocation (Line 6/Line 10)	8.5243%	4.5364%	7.0530%	0.0000%	0.0000%	7.2237%	
	Plant Allocation Factor							
12	Total Transmission Investment	1,069,641,270	220,365,800	118,389,665	1,188,911	1,427,437	1,411,013,083	
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	15,933,341	12,288,281	3,286,072	0	0	31,507,694	w/s 3A line 2
14	*= Revised Numerator (Line 12 + Line 13)*	1,085,574,611	232,654,081	121,675,737	1,188,911	1,427,437	1,442,520,777	
15	Total Plant in Service	4,539,478,706	1,887,061,320	703,349,353	1,188,911	1,427,637	7,132,505,927	FF1 206-207 ln 100
16	Percent Allocation (Line 14 / Line 15)	23.9141%	12.3289%	17.2995%	100.0000%	99.9860%	20.2246%	

Worksheet 5B

Northeast Utilities System Companies
Adjusted Allocation Factors
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Calendar Year 2006
POST - 1996

Line No.	**PTF Transmission Plant Allocation Factor**	CL&P	PSNH	WMECO	HWP	HP&E	TOTAL	Reference
1	PTF Transmission Investment	466,493,001	100,588,941	38,254,753	152,566	50,788	605,540,049	w/s 3A line 1
2	Total Transmission Investment	1,069,641,270	220,365,800	118,389,665	1,188,911	1,427,437	1,411,013,083	FF1 page 206-207 ln 58
3	Percent Allocation (Line 1/Line 2)	43.6121%	45.6463%	32.3126%	12.8324%	3.5580%	42.9153%	
	Transmission Wages and Salaries Allocation Factor							
4	Direct Transmission Wages and Salaries	5,494,992	1,667,036	964,188	-	-	8,126,216	FF1 page 354 ln 21
5	Affiliated Company Transmission Wages and Salaries	6,891,657	1,432,816	885,580	-	-	9,210,053	w/s 6 line 15
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	12,386,649	3,099,852	1,849,768	-	-	17,336,269	
7	Total Wages and Salaries	97,235,431	65,256,321	18,345,322	-	-	180,837,074	FF1 page 354 ln 28
8	Administrative and General Wages and Salaries	10,037,206	9,585,028	1,956,464	-	-	21,578,698	FF1 page 354 ln 27
9	Affiliated Company Wages and Salaries less A&G	58,112,043	12,661,465	9,837,693	122,206	-	80,733,407	w/s 6 line 30
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	145,310,268	68,332,758	26,226,551	122,206	-	239,991,783	
11	Percent Allocation (Line 6/Line 10)	8.5243%	4.5364%	7.0530%	0.0000%	0.0000%	7.2237%	
	Plant Allocation Factor							
12	Total Transmission Investment	1,069,641,270	220,365,800	118,389,665	1,188,911	1,427,437	1,411,013,083	
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	15,933,341	12,288,281	3,286,072	-	-	31,507,694	w/s 3A line 2
14	*= Revised Numerator (Line 12 + Line 13)*	1,085,574,611	232,654,081	121,675,737	1,188,911	1,427,437	1,442,520,777	
15	Total Plant in Service	4,539,478,706	1,887,061,320	703,349,353	1,188,911	1,427,637	7,132,505,927	FF1 206-207 ln 100
16	Percent Allocation (Line 14 / Line 15)	23.9141%	12.3289%	17.2995%	100.0000%	99.9860%	20.2246%	

Attachment A

Connecticut Light and Power Company
Substations and Lines
PTF Investment as of 12/31/07 (101 + 106)
REVISED 4-25-11 For M-N PROJECT FINAL 12C

	350	352	353	354	355	356	357	358	359	361	362	Grand Total
1997	39,442.79	38,745.58	6,814,154.09	112,607.52	118,897.46	4,837,106.76				15,699.31	60,978.30	12,037,631.82
1998	(6,147.32)	55,322.47	458,074.47		271,157.97	105,664.19				13,170.71	19,990.11	917,232.60
1999			1,049,728.22	28,802.26	26,718.64	6,688.86				6,017.57	30,817.16	1,148,772.72
2000			2,985,285.31		350,683.57	5,663.06	136,633.03	179,004.16	61,360.97	37,615.85	195,730.08	3,951,976.04
2001		226,889.06	18,349,057.67		1,628,177.46	37,263.90					22,353.52	20,263,741.62
2002		104,473.86	6,452,296.72	184,907.20	1,932,736.37	2,939,424.59				153,402.68	164,219.35	11,931,460.77
2003	(30,877.09)	177,461.93	15,366,214.60	55,332.28	9,222,450.34	2,547,946.34				25,279.84	70,183.90	27,433,992.14
2004	604,093.57	1,827,055.99	59,258,456.51		2,462,718.91	236,167.79	1,068,563.42	1,191,273.47	18,824.61	7,876.16	316,443.29	66,991,473.73
2005	2,350,091.18	4,611,226.77	75,911,876.61		3,572,063.92	4,497,456.48	16,440,131.15	9,216,659.97		151,857.39	231,366.88	116,982,730.34
2006	1,950,549.34	7,322,379.59	73,121,121.24		19,212,490.36	9,477,088.44	20,612,824.84	67,931,369.86	3,984,047.03	883,116.64	3,503,518.81	207,998,506.16
2007	132,484.07	94,472.68	32,273,169.65		7,047,775.48	106,767,877.76			39,441.39	4,712.10	5,093,572.21	151,453,505.36
Post-1996	5,039,636.55	14,458,027.93	292,039,435.09	381,649.26	45,845,870.48	131,458,348.17	38,258,152.44	78,518,307.46	4,103,674.00	1,298,748.26	9,709,173.64	621,111,023.30

Attachment B

Adjusted Transmission Related Taxes and Fees
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Calendar Year 2006

Ln.	Tax - Description	CL&P	PSNH	WMECO	HWP	HP&E	TOTAL	Reference
1	CT Gross Earnings Tax	2,270,690	-	-	-	-	2,270,690	FF1 p 262 FN
2	CT Excise Tax	3,113	110	59	-	24	3,306	
3	NH Excise Tax	-	-	126	-	-	126	
4	Fed. Excise Tax	-	-	-	-	-	-	
5	Mass. Excise Tax		-	-	-	-	-	
6	Corporation Business Tax	-	-	651	-	-	651	
7	MA Sales Tax	-	-	685	-	-	685	
8	CT Sales Tax		719	388	-	-	1,107	
9	NH Business Enterprise Tax	621	50,233	-	-	-	50,854	
10	NY Business Franchise Tax	9	4	2	-	-	15	
11	MA Business Franchise Tax			40,416	-	2,895	43,311	
12	TOTAL (sum of lines 1 to 11)	2,274,433	51,066	42,327	-	2,919	2,370,745	To Total RR Wksht 1
13	Pre-97 %	37.7362%	43.3005%	53.7921%	83.0075%	91.9028%		w/s 5A
14	Total Pre-97 Related Exp. (line 12 x 13)	858,285	22,112	22,769	-	2,683	905,848	To w/s 1A
15	Post-96 %	43.6121%	45.6463%	32.3126%	12.8324%	3.5580%		w/s 5B
16	Total Post-96 Related Exp. (line 12 x 15)	991,928	23,310	13,677	-	104	1,029,019	To w/s 1B

Attachment C

Adjusted Short Term Through and Out Revenues
Used in the development of 2006 PTF Revenue Requirements
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects

		CL&P	PSNH	WMECO	HWP	HP&E	TOTAL	Reference
1	2006 Through and Out Revenues	666,354	166,934	92,492	770	507	927,057	FF1 pg 328.1 - 330.1
2	Less: LT Revs	-	-	-	-	-	-	
3	ST T/O Revenues (line 1-2)	666,354	166,934	92,492	770	507	927,057	
4	RTO ROE Adjustm.	44,283	10,686	5,981	72	30	61,051	
5	NET ST T/O Revs. (line 3-4)	622,071	156,248	86,511	698	477	866,006	
6	Pre-1997 PTF Plant	403,642,354	95,419,451	63,684,238	986,885	1,311,855	565,044,783	
7	Post-1996 PTF Plant	466,493,001	100,588,941	38,254,753	152,566	50,788	605,540,049	Attachment A
8	Total PTF Plant (line 6+7)	870,135,355	196,008,392	101,938,991	1,139,451	1,362,643	1,170,584,832	
9	Ratio of Pre to Total (Line 6 / 8)	46.39%	48.68%	62.47%	86.61%	96.27%		
10	Ratio of Post to Total (Line 7 / 8)	53.61%	51.32%	37.53%	13.39%	3.73%		
		100.00%	100.00%	100.00%	100.00%	100.00%		
	Revenue Credits Allocated to Pre-1997 and Post-1996 Revenue Requirements:							
11	Pre-1997 Revenue Credit (line 3 * 9)	309,122	81,263	57,780	667	488	449,320	to w/s 1A, 1A-1, 1A-2
12	Post-1996 Revenue Credit (line 3 * 10)	357,232	85,671	34,712	103	19	477,737	to w/s 1B, 1B-1, 1B-2
13	Total Revenue Credit (line 11+12)	666,354	166,934	92,492	770	507	927,057	

Adjusted Capitalization - CL&P

To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects

Calendar Year 2006

Line No.	Long Term Debt	Year End	Reference
1	Outstanding Bonds (A/C 221 & 224)	1,290,323,780	FF1 pg 257 ln. 33 + pg 256.1, ln 13 fn (PCRB Principal)
2	Premium / (Discount) on LTD (A/C 225/226)	(1,753,575)	FF1 page 112 ln. 22 & ln. 23
3	Less Debt Expense (A/C 181)	14,026,203	FF1 page 111 ln. 69
4	Gain on Reacquired Debt (A/C 257)	-	FF1 page 113 ln. 61
5	**Total LTD (Year End) line 1+2-3+4)**	**1,274,544,002**	
6	**Total LTD (Beginning of Year / End of Year Average)**	**1,150,141,752**	(Line 6 + prior YE capitalization) / 2
7	Annual Amort of Prem Disc. & Exp. (A/C 428 minus A/C 429)	892,012	FF1 page 117 ln. 63 minus ln. 65
8	Annual Amort of Gain on Reacquired Debt (A/C 429.1)	-	FF1 page 117 ln. 66
9	Annual Interest Cost (A/C 207)	79,158,382	FF1 pg 257 ln. 33 + pg 256.1, ln 13 fn (PCRB Interest)
10	**Total Annual Cost (line 7-8+9)**	80,050,394	
11	**LTD Cost of Capital (line 10/6)**	**6.96%**	
	Preferred Stock		
12	Outstanding Stock (A/C 204)	116,200,000	FF1 page 112 ln. 3
13	Premium on PS (A/C 207)	820,027	G/L
14	Discount on PS (A/C 213)		
15	Unamortized Issue Expense (A/C 214)	647,015	FF1 page 112 ln. 10
16	**Net Proceeds (Year End) line 12+13-14-15**	**116,373,012**	
17	Issue Expense Amortization (A/C 214)	185,549	FF1 page 112 ln. 10 (diff. in py & cy)
18	Dividend (A/C 437)	5,558,609	FF1 page 118 ln. 25
19	**Annual Expense (line 17+18)**	5,744,158	
20	**PS Cost of Capital (line 19/16)**	**4.94%**	
21	Proprietary Capital	1,367,229,615	FF1 page 112 ln. 16
22	**Common Equity (line 21-16)**	**1,250,856,603**	

Adjusted 2006 AFUDC Equity Amortization in Depreciation

To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects

PRE-97

	a	b	c	d	e	f	g	h
	Transmission	PTF Allocator	Transmission PTF level (a*b)	General Transmission	PTF Allocator	General PTF level (d*e)	Total at PTF level (c+f)	Total Transmission (a + d)
CL&P	667,495	37.7362%	251,887	3,768	37.7362%	1,422	253,309	671,263
PSNH	88,240	43.3005%	38,208	1,999	43.3005%	866	39,074	90,239
WMECO	25,982	53.7921%	13,976	422	53.7921%	227	14,203	26,404
HWP	-	83.0075%	-	-	83.0075%	-	-	-
HP&E	-	91.9028%	-	-	91.9028%	-	-	-
	781,717		304,072	6,189		2,514	306,586	787,906

Adjusted 2006 AFUDC Equity Amortization in Depreciation

To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects

POST-96

	a	b	c	d	e	f	g	h
	Transmission	PTF Allocator	Transmission PTF level (a*b)	General Transmission	PTF Allocator	General PTF level (d*e)	Total at PTF level (c+f)	Total Transmission (a + d)
CL&P	667,495	43.6121%	291,109	3,768	43.6121%	1,643	292,752	671,263
PSNH	88,240	45.6463%	40,278	1,999	45.6463%	912	41,191	90,239
WMECO	25,982	32.3126%	8,395	422	32.3126%	136	8,532	26,404
HWP	-	12.8324%	-	-	12.8324%	-	-	-
HP&E	-	3.5580%	-	-	3.5580%	-	-	-
	781,717		339,782	6,189		2,692	342,474	787,906

Note: This worksheet represents the "C" component of the Federal & State Income Tax Formula.

Exhibit 2

Adjusted 2007 PTF Revenue Requirements To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects

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

Submitted on: 18-May-11

Revenue Requirements for (year): June 1, 2008 - May 31, 2009

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

	Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	= -	(a)	-	(g)
Total of Attachment F - Section J - Support Revenue	-	(b)	-	(h)
Total of Attachment F - Section K - Support Expense	-	(c)	-	(i)
Total of Attachment F - Section (L through O)	-	(d)	-	(j)
Sub Total - Sum (A through I) - J + K + (L through O)	-	(e)=(a)-(b)+(c)+(d)	-	(k)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	-		-	(l)
Annual True-up (per Attachment C to Attachment F Implementation Rule)	$6,194,345	(m)	$ 15,599,490	(n)
Adjusted Sub Total (Sub Total + True-up)		(o) = (e)+(f)+(m)		(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)				(q) = (o) + (p)

Note: This revised PTO Annual Transmission Revenue Requirements sheet dated May 18, 2011 only reflects the revised annual true-up as a result of ISO-NE Final Schedule 12C determinations for the Middletown-Norwalk and Glenbrook Cables Projects. (see Attachment K for the incremental refund)

Worksheet 1A

Northeast Utilities System Companies'
Adjsuted Annual Revenue Requirements of PTF Facilities for costs in 2007
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
for Rates billed June 1, 2008 - May 31, 2009
Pre-1997

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	CL&P	PSNH	WMECO	HWP	HP&E	Total	Reference
1	Transmission Plant	(A)(1)(a)	394,346,801	94,756,037	63,415,636	817,677	1,311,855	554,648,006	w/s 3A line 1
2	General Plant	(A)(1)(b)	5,896,146	4,318,853	2,126,923	-	-	12,341,922	w/s 3A line 2
3	Plant Held For Future Use	(A)(1)(c)	16,569,827	1,492,363	65,049	-	-	18,127,239	w/s 3A line 4
4	Total Plant (Lines 1+2+3)		416,812,774	100,567,253	65,607,608	817,677	1,311,855	585,117,167	
5	Accumulated Depreciation	(A)(1)(d)	101,387,238	31,671,709	24,453,895	565,831	1,080,194	159,158,867	w/s 3A line 7
6	Accumulated Deferred Income Taxes	(A)(1)(e)	26,969,763	10,860,130	9,112,464	-	32,076	46,974,433	w/s 3A line 10
7	Loss On Reacquired Debt	(A)(1)(f)	1,130,557	402,119	48,324	-	-	1,581,000	w/s 3A line 11
8	Other Regulatory Assets	(A)(1)(g)	4,543,921	329,783	4,441,575	-	-	9,315,279	w/s 3A line 15
9	Net Investment (Line 4-5-6+7+8)		294,130,251	58,767,316	36,531,148	251,846	199,585	389,880,146	
10	Prepayments	(A)(1)(h)	5,050,927	480,190	93,840	-	-	5,624,957	w/s 3A line 16
11	Materials & Supplies	(A)(1)(i)	4,525,147	1,226,843	387,725	-	-	6,139,715	w/s 3A line 17
12	Cash Working Capital	(A)(1)(j)	2,149,243	664,660	522,545	(5,961)	1,380	3,331,867	w/s 3A line 24
13	Total Investment Base (Line 9+10+11+12)		305,855,568	61,139,009	37,535,258	245,885	200,965	404,976,685	
II.	REVENUE REQUIREMENTS								
14	Investment Return and Income Taxes	(A)	40,072,493	7,490,097	4,613,999	48,654	38,490	52,263,733	w/s 2A
15	Depreciation Expense	(B)	8,606,555	1,884,398	1,159,059	2,752	20,079	11,672,843	w/s 4A line 3
16	Amortization of Loss on Reacquired Debt	(C)	97,035	43,042	1,262	-	-	141,339	w/s 4A line 4
17	Investment Tax Credit	(D)	(232,520)	(10,441)	(31,569)	-	-	(274,530)	w/s 4A line 5
18	Property Tax Expense	(E)	3,942,943	1,566,521	1,106,352	6,770	40,344	6,662,930	w/s 4A line 8
19	Payroll Tax Expense	(F)	184,116	48,927	26,226	-	-	259,269	w/s 4A line 19
20	Operation & Maintenance Expense	(G)	8,527,428	2,849,667	2,156,534	2,700	48	13,536,377	w/s 4A line 17
21	Administrative & General Expense	(H)	8,123,792	2,467,615	1,633,094	(63,229)	10,992	12,172,264	w/s 4A line 18
22	Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	-	-	
23	Transmission Support Revenue	(J)	(1,379,737)	(2,748,624)	-	-	-	(4,128,361)	
24	Transmission Support Expense	(K)	1,922,457	1,116,241	390,732	12,840	-	3,442,270	
25	Transmission Related Expense from Generators	(L)	-	-	-	-	-	-	
26	Transmission Related Taxes and Fees Charge	(M)	1,543,092	18,203	3,750	-	22	1,565,067	Attachment B line 13
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(582,764)	(120,041)	(88,424)	(330)	(829)	(792,388)	Attachment C line 11
28	Transmission Rents Received from Electric Property	(O)	(4,120,785)	(1,363,273)	(291,674)	-	-	(5,775,732)	
29	Total Revenue Requirements (Line 14 thru 28)		66,704,105	13,242,332	10,679,341	10,157	109,146	90,745,081	

Pre 97 - at 11.64%

Worksheet 1B

Northeast Utilities System Companies'
Adjusted Annual Revenue Requirements of PTF Facilities for costs in 2007
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
for Rates billed June 1, 2008 - May 31, 2009
Post - 1996

Line No.		Attachment F Reference *Section:*	CL&P	PSNH	WMECO	HWP	HP&E	Total	Reference
	I. INVESTMENT BASE								
1	Transmission Plant	(A)(1)(a)	621,111,023	134,064,671	47,515,433	387,026	50,788	803,128,941	w/s 3A line 1
2	General Plant	(A)(1)(b)	9,286,636	6,110,487	1,593,641	-	-	16,990,764	w/s 3A line 2
3	Plant Held For Future Use	(A)(1)(c)	26,098,058	2,111,456	48,739	-	-	28,258,253	w/s 3A line 4
4	Total Plant (Lines 1+2+3)		656,495,717	142,286,614	49,157,813	387,026	50,788	848,377,958	
5	Accumulated Depreciation	(A)(1)(d)	159,688,450	44,810,407	18,322,582	267,822	41,820	223,131,081	w/s 3A line 7
6	Accumulated Deferred Income Taxes	(A)(1)(e)	42,478,320	15,365,349	6,827,701	-	1,242	64,672,612	w/s 3A line 10
7	Loss On Reacquired Debt	(A)(1)(f)	1,780,667	568,934	36,208	-	-	2,385,809	w/s 3A line 11
8	Other Regulatory Assets	(A)(1)(g)	7,156,834	466,590	3,327,941	-	-	10,951,365	w/s 3A line 15
9	Net Investment (Line 4-5-6+7+8)		463,266,448	83,146,382	27,371,679	119,204	7,726	573,911,439	
10	Prepayments	(A)(1)(h)	7,955,387	679,393	70,311	-	-	8,705,091	w/s 3A line 16
11	Materials & Supplies	(A)(1)(i)	7,127,265	1,735,787	290,511	-	-	9,153,563	w/s 3A line 17
12	Cash Working Capital	(A)(1)(j)	3,278,282	940,388	354,932	(3,581)	49	4,570,070	w/s 3A line 24
13	Total Investment Base (Line 9+10+11+12)		481,627,382	86,501,950	28,087,433	115,623	7,775	596,340,163	
	II. REVENUE REQUIREMENTS								
14	Investment Return and Income Taxes	(A)	63,101,712	10,597,293	3,452,622	22,879	1,489	77,175,995	w/s 2A
15	Depreciation Expense	(B)	13,555,626	2,666,121	868,449	1,302	777	17,092,275	w/s 4A line 3
16	Amortization of Loss on Reacquired Debt	(C)	152,834	60,898	946	-	-	214,678	w/s 4A line 4
17	Investment Tax Credit	(D)	(366,227)	(14,772)	(23,654)	-	-	(404,653)	w/s 4A line 5
18	Property Tax Expense	(E)	6,210,273	2,216,377	828,957	3,204	1,562	9,260,373	w/s 4A line 8
19	Payroll Tax Expense	(F)	289,989	69,223	19,650	-	-	378,862	w/s 4A line 19
20	Operation & Maintenance Expense	(G)	13,430,999	4,031,824	1,615,827	1,277	2	19,079,929	w/s 4A line 17
21	Administrative & General Expense	(H)	12,795,257	3,491,281	1,223,629	(29,928)	391	17,480,630	w/s 4A line 18
22	Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	-	-	
23	Transmission Related Expense from Generators	(L)		-	-	-	-	-	
24	Transmission Related Taxes and Fees Charge	(M)	2,430,424	25,755	2,810	-	1	2,458,990	Attachment B line 15
25	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(918,044)	(169,842)	(66,245)	(156)	(32)	(1,154,319)	Attachment C line 12
26	Total Revenue Requirements (Line 14 thru 25)		110,682,843	22,974,158	7,922,991	(1,422)	4,190	141,582,760	

Post 96 - at 11.64%

Northeast Utilities System Companies'

Adjusted Annual Revenue Requirements of post-2003 PTF Incremental Return for costs in 2007
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
for Rates billed November 1, 2008 - May 31, 2009

Line		CL&P	PSNH	WMECO	Total	Reference
	I. INVESTMENT BASE					
1	Transmission Plant	$ 460,291,240	$ 68,205,093	$ 11,420,749	$ 539,917,082	Attachment A1
2	Accumulated Depreciation	$ 16,111,925	$ 2,482,829	$ 570,499	$ 19,165,253	↓
3	Accumulated Deferred Income Taxes	$ 22,825,567	$ 3,196,778	$ 598,922	$ 26,621,267	
4	Net Investment (Line 1-2-3)	$ 421,353,748	$ 62,525,486	$ 10,251,328	$ 494,130,562	
	II. INCREMENTAL RETURN					
5	Incremental Revenue Requirements	$ 3,433,907	$ 515,135	$ 84,339	$ 4,033,381	w/s 2A

Worksheet 1D

Northeast Utilities System Companies'
Adjusted Transmission Revenue Requirements of PTF Facilities
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
2007 True-up
Pre-97 and Post-96

Line	I. ANNUAL TRUE-UP PER FERC ROE ORDER	PRE-97	POST-96	TOTAL	Reference
1	True-up 2007 Actual Annual RR @ 11.64% ROE	91,452,645	148,318,927	239,771,572	2007 ATRR
2	Adjusted 2007 True-up for MN/GB 12-C decsion	90,745,081	145,616,141	236,361,222	w/s 1A & w/s 1B + 1C
3	Total Rate Year Surcharge/(Refund) (Line 2 - 1)	(707,564)	(2,702,786)	(3,410,350)	

Northeast Utilities System Companies'
FERC Interest Calculation associated with Surcharge / (Refund)
Adjusted Transmission Revenue Requirements of PTF Facilities
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
PRE-97 / Post 96

	Surcharge / (Refund)
Pre	(707,564)
Post	($2,702,786)

Initial Billing Period	Balance Pre 97	Balance Post 96	FERC Monthly Interest Rate	Interest Pre 97	Interest Post 96
June 2007	$ (707,564)	$ (2,702,786)	0.68%	$ (4,811)	$ (18,379)
July 2007	$ (712,375)	$ (2,721,165)	0.70%	$ (4,987)	$ (19,048)
August 2007	$ (712,375)	$ (2,721,165)	0.70%	$ (4,987)	$ (19,048)
September 2007	$ (712,375)	$ (2,721,165)	0.68%	$ (4,844)	$ (18,504)
October 2007	$ (727,193)	$ (2,777,765)	0.70%	$ (5,090)	$ (19,444)
November 2007	$ (727,193)	$ (2,777,765)	0.68%	$ (4,945)	$ (18,889)
December 2007	$ (727,193)	$ (2,777,765)	0.70%	$ (5,090)	$ (19,444)
January 2008	$ (742,318)	$ (2,835,542)	0.66%	$ (4,899)	$ (18,715)
February 2008	$ (742,318)	$ (2,835,542)	0.62%	$ (4,602)	$ (17,580)
March 2008	$ (742,318)	$ (2,835,542)	0.66%	$ (4,899)	$ (18,715)
April 2008	$ (756,718)	$ (2,890,552)	0.56%	$ (4,238)	$ (16,187)
May 2008	$ (756,718)	$ (2,890,552)	0.57%	$ (4,313)	$ (16,476)
June 2008	$ (756,718)	$ (2,890,552)	0.56%	$ (4,238)	$ (16,187)
July 2008	$ (769,507)	$ (2,939,402)	0.45%	$ (3,463)	$ (13,227)
August 2008	$ (769,507)	$ (2,939,402)	0.45%	$ (3,463)	$ (13,227)
September 2008	$ (769,507)	$ (2,939,402)	0.44%	$ (3,386)	$ (12,933)
October 2008	$ (779,819)	$ (2,978,789)	0.42%	$ (3,275)	$ (12,511)
November 2008	$ (779,819)	$ (2,978,789)	0.41%	$ (3,197)	$ (12,213)
December 2008	$ (779,819)	$ (2,978,789)	0.42%	$ (3,275)	$ (12,511)

Worksheet 1D

Initial Billing Period	Balance		FERC Monthly Interest Rate	Interest	
	Pre 97	Post 96		Pre 97	Post 96
January 2009	$ (789,566)	$ (3,016,024)	0.38%	$ (3,000)	$ (11,461)
February 2009	$ (789,566)	$ (3,016,024)	0.34%	$ (2,685)	$ (10,254)
March 2009	$ (789,566)	$ (3,016,024)	0.38%	$ (3,000)	$ (11,461)
April 2009	$ (798,251)	$ (3,049,200)	0.28%	$ (2,235)	$ (8,538)
May 2009	$ (798,251)	$ (3,049,200)	0.29%	$ (2,315)	$ (8,843)
June 2009	$ (798,251)	$ (3,049,200)	0.28%	$ (2,235)	$ (8,538)
July 2009	$ (805,036)	$ (3,075,119)	0.28%	$ (2,254)	$ (8,610)
August 2009	$ (805,036)	$ (3,075,119)	0.28%	$ (2,254)	$ (8,610)
September 2009	$ (805,036)	$ (3,075,119)	0.27%	$ (2,174)	$ (8,303)
October 2009	$ (811,718)	$ (3,100,642)	0.28%	$ (2,273)	$ (8,682)
November 2009	$ (811,718)	$ (3,100,642)	0.27%	$ (2,192)	$ (8,372)
December 2009	$ (811,718)	$ (3,100,642)	0.28%	$ (2,273)	$ (8,682)
January 2010	$ (818,456)	$ (3,126,378)	0.28%	$ (2,292)	$ (8,754)
February 2010	$ (818,456)	$ (3,126,378)	0.25%	$ (2,046)	$ (7,816)
March 2010	$ (818,456)	$ (3,126,378)	0.28%	$ (2,292)	$ (8,754)
April 2010	$ (825,086)	$ (3,151,702)	0.27%	$ (2,228)	$ (8,510)
May 2010	$ (825,086)	$ (3,151,702)	0.28%	$ (2,310)	$ (8,825)
June 2010	$ (825,086)	$ (3,151,702)	0.27%	$ (2,228)	$ (8,510)
July 2010	$ (831,852)	$ (3,177,547)	0.28%	$ (2,329)	$ (8,897)
August 2010	$ (831,852)	$ (3,177,547)	0.28%	$ (2,329)	$ (8,897)
September 2010	$ (831,852)	$ (3,177,547)	0.27%	$ (2,246)	$ (8,579)
October 2010	$ (838,756)	$ (3,203,920)	0.28%	$ (2,349)	$ (8,971)
November 2010	$ (838,756)	$ (3,203,920)	0.27%	$ (2,265)	$ (8,651)
December 2010	$ (838,756)	$ (3,203,920)	0.28%	$ (2,349)	$ (8,971)
January 2011	$ (845,719)	$ (3,230,513)	0.28%	$ (2,368)	$ (9,045)
February 2011	$ (845,719)	$ (3,230,513)	0.25%	$ (2,114)	$ (8,076)
March 2011	$ (845,719)	$ (3,230,513)	0.28%	$ (2,368)	$ (9,045)
April 2011	$ (852,569)	$ (3,256,679)	0.27%	$ (2,302)	$ (8,793)
May 2011	$ (852,569)	$ (3,256,679)	0.28%	$ (2,387)	$ (9,119)
	Total Surcharge/(Refund)			**$ (857,258)**	**$ (3,274,591)**

	Interest	Principal	Total (check)	variance
Pre 97	$ (149,694)	$ (707,564)	$ (857,258)	$ -
Post 96	$ (571,805)	$ (2,702,786)	$ (3,274,591)	$ -
	$ (721,499)	$ (3,410,350)	$ (4,131,849)	

Worksheet 2A

Connecticut Light & Power Company (CL&P)
Adjusted Investment Return and Income Taxes - 2007
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Pre 97
for Rates billed June 1, 2008 - May 31, 2009

	CAPITALIZATION 12/31/2007	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 1,769,383,331	47.46%	6.84%	3.25%	
PREFERRED STOCK	$ 116,513,592	3.13%	4.89%	0.15%	0.15%
COMMON EQUITY	$ 1,841,937,187	49.41%	11.64%	5.75%	5.75%
TOTAL INVESTMENT RETURN	$ 3,727,834,110	100.00%		9.15%	5.90%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.09150

(b) Federal Income Tax

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

$$= \frac{5.9000\% \ +(\ (232{,}520) + 411{,}807\ )\ /\ 305{,}855{,}568\ )\ \times\ 35.00\%\ )}{(\ 1 - 0.35\ )}$$

= 0.0320849

(c) State Income Tax

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

$$= \frac{0.0590 \ +(\ (232{,}520) + 411{,}807\ )\ /\ 305{,}855{,}568\ ) + 0.0320849\ )^{*}\ 0.075}{(\ 1 - 0.075\ )}$$

= 0.0074328

(a)+(b)+(c) Cost of Capital Rate = 0.1310177

	Pre-1997 PTF	
INVESTMENT BASE	305,855,568	From Worksheet 1, line 13
x Cost of Capital Rate	0.1310177	
= Investment Return and Income Taxes	$ 40,072,493	From Worksheet 1, line 14

Worksheet 2A

Connecticut Light & Power Company (CL&P)
Adjusted Investment Return and Income Taxes - 2007
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
POST-96
for Rates billed June 1, 2008 - May 31, 2009

	CAPITALIZATION 12/31/2007	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 1,769,383,331	47.46%	6.84%	3.25%	
PREFERRED STOCK	$ 116,513,592	3.13%	4.89%	0.15%	0.15%
COMMON EQUITY	$ 1,841,937,187	49.41%	11.64%	5.75%	5.75%
TOTAL INVESTMENT RETURN	$ 3,727,834,110	100.00%		9.15%	5.90%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.09150

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) x Federal Income Tax Rate)

(1 - Federal Income Tax Rate)

= 5.9000% +((366,227) + 648,610) / 481,627,382) x 35.00%)

(1 - 0.35)

= 0.0320849

(c) State Income Tax = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate

(1 - State Income tax Rate)

= 0.0590 +((366,227) + 648,610) / 481,627,382) + 0.0320849)* 0.075

(1 - 0.075)

= 0.0074328

(a)+(b)+(c) Cost of Capital Rate = 13.1018%

	Post - 1996 PTF	
INVESTMENT BASE	481,627,382	From Worksheet 1, line 13
x Cost of Capital Rate	0.1310177	
= Investment Return and Income Taxes	$ 63,101,712	From Worksheet 1, line 14

Worksheet 2A
Post 2003

Connecticut Light & Power Company (CL&P)
Adjusted Investment Return and Income Taxes - 2007
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Post 2003
Incremental ROE Adder for RSP Projects

	CAPITALIZATION 12/31/2007	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 1,769,383,331	47.46%	#N/A		
PREFERRED STOCK	116,513,592	3.13%			
COMMON EQUITY	1,841,937,187	49.41%	1.00%	0.49%	0.49%
TOTAL INVESTMENT RETURN	$ 3,727,834,110	100.00%		0.49%	0.49%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0049

(b) Federal Income Tax

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

$$= \frac{0.0049 + ((0 + 0) / 421{,}353{,}748) \times 0.35)}{(1 - 0.35)}$$

$$= 0.0026385$$

(c) State Income Tax

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

$$= \frac{0.0049 + ((0 + 0) / 421{,}353{,}748) + 0.0026385)^{*}\ 0.075}{(1 - 0.075)}$$

$$= 0.0006112$$

(a)+(b)+(c) Cost of Capital Rate = 0.0081497

	(post-2003 PTF)	
INVESTMENT BASE	$ 421,353,748	From Worksheet 1 Line 4
x Cost of Capital Rate	0.0081497	
= Investment Return and Income Taxes	3,433,907	To Worksheet 1a Line 5

Connecticut Light & Power Company (CL&P)
Adjusted Rate Base Items
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Calendar Year 2007

					PRE-97 PTF		POST-96 PTF		
		(1)	(2)	(3) = (1)*(2)	(4)	(5) = (3)*(4)	(6)	(7) = (3)*(6)	
Line No.		Total	Wage/Plant Allocation Factors (a)	Transmission Allocated	PTF Allocation Factor (b)	PTF Allocated	PTF Allocation Factor (b)	PTF Allocated	Reference
	Transmission Plant								
1	Transmission Plant					394,346,801		621,111,023	Attachment A
2	General Plant	18,725,472		18,725,472	31.4873%	5,896,146	49.5936%	9,286,636	FF1 page 204 ln. 99, footnote
3	Total (line 1+2)	18,725,472		18,725,472		400,242,947		630,397,659	
4	Transmission Plant Held for Future Use	52,623,843	(c)	52,623,843	31.4873%	16,569,827	49.5936%	26,098,058	(c)
	Transmission Accumulated Depreciation (b)								
5	Transmission Accum. Depreciation	310,632,760		310,632,760	31.4873%	97,809,869	49.5936%	154,053,968	FF1 page 219 ln. 25
6	General Plant Accum.Depreciation	11,361,308		11,361,308	31.4873%	3,577,369	49.5936%	5,634,482	FF1 page 219 ln. 28, footnote
7	Total (line 5+6)	321,994,068		321,994,068		101,387,238		159,688,450	
	Transmission Accumulated Deferred Taxes								
8	Accumulated Deferred Taxes (281 to 283)	(113,635,938)		(113,635,938)	31.4873%	(35,780,889)	49.5936%	(56,356,153)	FF1 page 274 ln. 9 & 276 ln. 19, footnote
9	Accumulated Deferred Taxes (190)	27,983,112	(d)	27,983,112	31.4873%	8,811,126	49.5936%	13,877,833	(d)
10	Total (line 8+9)	(85,652,826)		(85,652,826)		(26,969,763)		(42,478,320)	
11	Transmission loss on Reacquired Debt	3,590,518		3,590,518	31.4873%	1,130,557	49.5936%	1,780,667	FF1 page 111 ln. 81, footnote
	Other Regulatory Assets								
12	FAS 106	-		-	31.4873%	-	49.5936%	-	FF1 page 232
13	FAS 109	19,052,115		19,052,115	31.4873%	5,998,997	49.5936%	9,448,630	FF1 page 232 ln. 1, footnote
14	Other Regulatory Liabilities (254.DK)	(4,621,152)		(4,621,152)	31.4873%	(1,455,076)	49.5936%	(2,291,796)	FF1 page 278 ln. 5, footnote
15	Total (line 12+13+14)	14,430,963		14,430,963		4,543,921		7,156,834	
16	Transmission Prepayments (165)	16,041,156		16,041,156	31.4873%	5,050,927	49.5936%	7,955,387	FF1 page 110 ln. 57, footnote
17	Transmission Materials and Supplies	14,371,340		14,371,340	31.4873%	4,525,147	49.5936%	7,127,265	FF1 page 227 ln. 8
18	Cash Working Capital								
19	Operation & Maintenance Expense					8,527,428		13,430,999	w/s 4a, Line 17
20	Administrative & General Expense					8,123,792		12,795,257	w/s 4a, Line 18
21	Transmission Support Expense					542,720		-	w/s 7
22	Subtotal (line 19+20+21)					17,193,940		26,226,256	
23						0.125		0.125	x 45 / 360
24	Total (line 22 * line 23)					2,149,243		3,278,282	

(a) All B/S items functionalized per FERC Form 1; therefore, no need to use Wage/Plant Allocation Factor (column 2)
(b) Worksheet 5 line 3

(c)	Account 105	55,181,847	FF1 page 214 ln. 40
	Less Royal Oaks Bypass	2,558,004	
		52,623,843	

(d)	Account 190	42,511,413	FF1 page 234 ln. 18, footnote
	Less Reserve for Disputed Transactions	14,528,301	
	Total Account 190	27,983,112	

Worksheet 4A

Connecticut Light & Power Company (CL&P)
Adjusted Expense Items
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Calendar Year 2007

					PRE-97 PTF		POST-96 PTF		
Line No.		(1) Total	(2) Wage/Plant Allocation Factors (a)	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) Pre-97 PTF Allocated	(6) PTF Allocation Factor (b)	(7) = (3)*(6) Post-96 PTF Allocated	Reference
	Depreciation Expense								
1	Transmission Depreciation	25,782,332		25,782,332	31.4873%	8,118,160	49.5936%	12,786,387	FF 1 page 336 ln. 7
2	General Depreciation	1,551,085		1,551,085	31.4873%	488,395	49.5936%	769,239	FF1 page 336 ln. 10, footnote
3	Total (line 1+2)	27,333,417		27,333,417		8,606,555		13,555,626	
4	Amortization of Loss on Reacquired Debt	308,172		308,172	31.4873%	97,035	49.5936%	152,834	FF1 page 117, ln. 64, footnote
5	Amortization of Investment Tax Credits	738,456		738,456	31.4873%	232,520	49.5936%	366,227	FF1 page 266 ln. 8, footnote - difference of PY-CY
	Property Taxes								
6	Transmission Property Taxes	12,522,327		12,522,327	31.4873%	3,942,943	49.5936%	6,210,273	FF1 page 262 ln. 25, footnote
7	General Property Taxes (c)	-		-	31.4873%	-	49.5936%	-	
8	Total (line 6+7)	12,522,327		12,522,327		3,942,943		6,210,273	
	Transmission Operation and Maintenance								
9	Operation and Maintenance	149,200,864		149,200,864	31.4873%	46,979,324	49.5936%	73,994,080	FF1 page 321 ln. 112
10	Transmission of Electricity by Others - #565	108,530,314		108,530,314	31.4873%	34,173,266	49.5936%	53,824,090	FF1 page 321 ln. 96
11	Load Dispatching - #561	-		-	31.4873%	-	49.5936%	-	FF1 page 321 ln. 84
12	Account 561.1	2,521,950		2,521,950	31.4873%	794,094	49.5936%	1,250,726	FF1 page 321 ln. 85
13	Account 561.2	5,307,583		5,307,583	31.4873%	1,671,215	49.5936%	2,632,221	FF1 page 321 ln. 86
14	Account 561.3	1,619,368		1,619,368	31.4873%	509,895	49.5936%	803,103	FF1 page 321 ln. 87
15	Account 561.4	4,139,529		4,139,529	31.4873%	1,303,426	49.5936%	2,052,941	FF1 page 321 ln. 88
16	**Station Expenses & Rents - #562 / #567	-		-		-		-	
17	O&M less lines 10 thru 16	27,082,120		27,082,120	31.4873%	8,527,428	49.5936%	13,430,999	
	Transmission Administrative and General								
18	Administrative and General	25,800,218		25,800,218	31.4873%	8,123,792	49.5936%	12,795,257	FF1 page 320 ln. 197, footnote
19	*Payroll Tax Expense*	*584,731*		584,731	31.4873%	184,116	49.5936%	289,989	
	Federal Unemployment	5,414							FF1 page 262, footnote
	FICA	426,330							FF1 page 262 ln. 4i, footnote
	Medicare	128,844							FF1 page 262 ln. 9i, footnote
	CT Unemployment	23,323							FF1 page 262 ln. 15i, footnote
	DC Unemployment	23							FF1 page 262 ln. 39i, footnote
	FL Unemployment	-							FF1 page 262.1 ln. 16i, footnote
	GA Unemployment	-							FF1 page 262 & 263 footnote
	MA Unemployment	56							FF1 page 262 ln. 33i, footnote
	MA Universal Health	31							FF1 page 262 ln. 34i, footnote
	NH Unemployment	315							FF1 page 262.1 ln. 5i, footnote
	NJ Unemployment	-							FF1 page 262 & 263 footnote
	NY Unemployment	395							FF1 page 262.1 ln. 12i, footnote
	Total	584,731	To Line 19						

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

(a) All expenses functionalized per FERC Form 1; therefore, no need to use Wage/Plant Allocation Factor (column 2)

(b) Worksheet 5, Line 3

(c) Transmission related general property taxes are included in the Transmission Property tax number footnoted in the FF1.

Northeast Utilites System Companies
Adjusted Allocation Factors
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Calendar Year 2007
PRE-1997

Line No.		CL&P	PSNH	WMECO	HWP	HP&E	TOTAL	Reference
	PTF Transmission Plant Allocation Factor							
1	PTF Transmission Investment	394,346,801	94,756,037	63,415,636	817,677	1,311,855	554,648,006	w/s 3A line 1
2	Total Transmission Investment	1,252,400,858	265,550,160	125,961,814	1,533,610	1,427,437	1,646,873,879	FF1 page 206-207 ln 58
3	Percent Allocation (Line 1 / Line 2)	31.4873%	35.6829%	50.3451%	53.3171%	91.9028%	33.6788%	
	Transmission Wages and Salaries Allocation Factor							
4	Direct Transmission Wages and Salaries	4,733,933	1,826,585	1,062,916	-	-	7,623,434	FF1 page 354 ln 21
5	Affiliated Company Transmission Wages and Salaries	9,775,499	1,489,432	865,748	-	-	12,130,679	w/s 6 line 15
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	14,509,432	3,316,017	1,928,664	-	-	19,754,113	
7	Total Wages and Salaries	87,257,187	69,492,451	17,468,222	-	-	174,217,860	FF1 page 354 ln 28
8	Administrative and General Wages and Salaries	12,770,352	10,782,850	2,555,978	-	-	26,109,180	FF1 page 354 ln 27
9	Affiliated Company Wages and Salaries less A&G	66,598,262	14,205,943	10,457,016	-	-	91,261,221	w/s 6 line 30
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	141,085,097	72,915,544	25,369,260	-	-	239,369,901	
11	Percent Allocation (Line 6 / Line 10)	10.2842%	4.5478%	7.6024%	0.0000%	0.0000%	8.2525%	
	Plant Allocation Factor							
12	Total Transmission Investment (Line 2)	1,252,400,858	265,550,160	125,961,814	1,533,610	1,427,437	1,646,873,879	
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	18,725,472	12,103,426	4,224,687	-	-	35,053,585	w/s 3A line 2
14	*= Revised Numerator (Line 12 + Line 13)*	1,271,126,330	277,653,586	130,186,501	1,533,610	1,427,437	1,681,927,464	
15	Total Plant in Service	4,821,469,016	1,997,798,512	726,268,282	1,533,610	1,427,637	7,548,497,057	FF1 206-207 ln 100
16	Percent Allocation (Line 14 / Line 15)	26.3639%	13.8980%	17.9254%	100.0000%	99.9860%	22.2816%	

Northeast Utilities System Companies
Adjusted Allocation Factors
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Calendar Year 2007
POST - 1996

Line No.	**PTF Transmission Plant Allocation Factor**	**CL&P**	**PSNH**	**WMECO**	**HWP**	**HP&E**	**TOTAL**	**Reference**
1	PTF Transmission Investment	621,111,023	134,064,671	47,515,433	387,026	50,788	803,128,941	w/s 3A line 1
2	Total Transmission Investment	1,252,400,858	265,550,160	125,961,814	1,533,610	1,427,437	1,646,873,879	FF1 page 206-207 ln 58
3	Percent Allocation (Line 1/ Line 2)	49.5936%	50.4856%	37.7221%	25.2363%	3.5580%	48.7669%	
	Transmission Wages and Salaries Allocation Factor							
4	Direct Transmission Wages and Salaries	4,733,933	1,826,585	1,062,916	-	-	7,623,434	FF1 page 354 ln 21
5	Affiliated Company Transmission Wages and Salaries	9,775,499	1,489,432	865,748	-	-	12,130,679	w/s 6 line 15
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	14,509,432	3,316,017	1,928,664	-	-	19,754,113	
7	Total Wages and Salaries	87,257,187	69,492,451	17,468,222	-	-	174,217,860	FF1 page 354 ln 28
8	Administrative and General Wages and Salaries	12,770,352	10,782,850	2,555,978	-	-	26,109,180	FF1 page 354 ln 27
9	Affiliated Company Wages and Salaries less A&G	66,598,262	14,205,943	10,457,016	-	-	91,261,221	w/s 6 line 30
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	141,085,097	72,915,544	25,369,260	-	-	239,369,901	
11	Percent Allocation (Line 6/ Line 10)	10.2842%	4.5478%	7.6024%	0.0000%	0.0000%	8.2525%	
	Plant Allocation Factor							
12	Total Transmission Investment (line 2)	1,252,400,858	265,550,160	125,961,814	1,533,610	1,427,437	1,646,873,879	
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	18,725,472	12,103,426	4,224,687	-	-	35,053,585	w/s 3A line 2
14	*= Revised Numerator (Line 12 + Line 13)*	1,271,126,330	277,653,586	130,186,501	1,533,610	1,427,437	1,681,927,464	
15	Total Plant in Service	4,821,469,016	1,997,798,512	726,268,282	1,533,610	1,427,637	7,548,497,057	FF1 206-207 ln 100
16	Percent Allocation (Line 14 / Line 15)	26.3639%	13.8980%	17.9254%	100.0000%	99.9860%	22.2816%	

Attachment A

Connecticut Light and Power Company
Substations and Lines
PTF Investment as of 12/31/07 (101 + 106)
REVISED 4-25-11 For M-N PROJECT FINAL 12C

	350	352	353	354	355	356	357	358	359	361	362	Grand Total
1997	39,442.79	38,745.58	6,814,154.09	112,607.52	118,897.46	4,837,106.76				15,699.31	60,978.30	12,037,631.82
1998	(6,147.32)	55,322.47	458,074.47		271,157.97	105,664.19				13,170.71	19,990.11	917,232.60
1999			1,049,728.22	28,802.26	26,718.64	6,688.86				6,017.57	30,817.16	1,148,772.72
2000			2,985,285.31		350,683.57	5,663.06	136,633.03	179,004.16	61,360.97	37,615.85	195,730.08	3,951,976.04
2001		226,889.06	18,349,057.67		1,628,177.46	37,263.90					22,353.52	20,263,741.62
2002		104,473.86	6,452,296.72	184,907.20	1,932,736.37	2,939,424.59				153,402.68	164,219.35	11,931,460.77
2003	(30,877.09)	177,461.93	15,366,214.60	55,332.28	9,222,450.34	2,547,946.34				25,279.84	70,183.90	27,433,992.14
2004	604,093.57	1,827,055.99	59,258,456.51		2,462,718.91	236,167.79	1,068,563.42	1,191,273.47	18,824.61	7,876.16	316,443.29	66,991,473.73
2005	2,350,091.18	4,611,226.77	75,911,876.61		3,572,063.92	4,497,456.48	16,440,131.15	9,216,659.97		151,857.39	231,366.88	116,982,730.34
2006	1,950,549.34	7,322,379.59	73,121,121.24		19,212,490.36	9,477,088.44	20,612,824.84	67,931,369.86	3,984,047.03	883,116.64	3,503,518.81	207,998,506.16
2007	132,484.07	94,472.68	32,273,169.65		7,047,775.48	106,767,877.76			39,441.39	4,712.10	5,093,572.21	151,453,505.36
Post-1996	5,039,636.55	14,458,027.93	292,039,435.09	381,649.26	45,845,870.48	131,458,348.17	38,258,152.44	78,518,307.46	4,103,674.00	1,298,748.26	9,709,173.64	621,111,023.30
Grand Total	43,986,182.66	18,510,656.24	396,239,559.50	26,862,897.27	148,940,246.13	212,786,460.67	39,076,063.25	84,472,092.90	11,026,696.17	6,462,629.44	27,094,340.13	1,015,457,824.37

Attachment A1

CL+P RSP INVESTMENT BY PLANT ACCOUNT AT 12-31-07
REVISED 4-25-11 For M-N PROJECT FINAL 12C

		Data		
Plant A/C	Year	Sum of Gross Plant2	Sum of Accum Depr2	Sum of Net Plant2
350	2004	423,777.17	21,104.27	402,672.90
	2005	2,350,091.18	85,413.55	2,264,677.63
	2006	1,863,874.34	41,555.58	1,822,318.76
	2007	122,815.01	36.24	122,778.77
350 Total		4,760,557.70	148,109.64	4,612,448.06
352	2004	1,166,407.66	105,335.86	1,061,071.80
	2005	4,486,550.41	294,592.10	4,191,958.31
	2006	7,303,979.54	293,545.41	7,010,434.14
352 Total		12,956,937.61	693,473.37	12,263,464.25
353	2004	55,530,375.05	4,015,061.02	51,515,314.03
	2005	65,805,289.63	3,455,500.91	62,349,788.72
	2006	66,615,369.73	2,157,182.34	64,458,187.40
	2007	8,846,279.47	96,178.35	8,750,101.12
353 Total		196,797,313.89	9,723,922.61	187,073,391.27
355	2004	233,478.02	31,671.21	201,806.81
	2005	2,648,700.69	250,684.57	2,398,016.12
	2006	17,034,574.55	949,873.61	16,084,700.94
	2007	289,147.34	5,324.64	283,822.70
355 Total		20,205,900.60	1,237,554.03	18,968,346.57
356	2004	163,768.35	16,291.70	147,476.65
	2005	2,616,404.93	187,539.61	2,428,865.32
	2006	6,347,921.16	275,407.68	6,072,513.48
	2007	96,053,040.00	1,402,145.78	94,650,894.22
356 Total		105,181,134.44	1,881,384.77	103,299,749.67
357	2004	1,068,563.42	24,323.23	1,044,240.19
	2005	16,440,131.15	334,225.40	16,105,905.75
	2006	20,612,824.84	335,592.87	20,277,231.98
357 Total		38,121,519.41	694,141.50	37,427,377.92
358	2004	1,191,273.47	34,387.31	1,156,886.16
	2005	9,216,659.97	235,418.94	8,981,241.03
	2006	67,931,369.86	1,373,360.84	66,558,009.02
	2007	0.00	0.00	0.00
358 Total		78,339,303.30	1,643,167.09	76,696,136.21
359	2006	3,928,573.16	90,172.45	3,838,400.71
359 Total		3,928,573.16	90,172.45	3,838,400.71
Grand Total		460,291,240.12	16,111,925.46	444,179,314.65

Attachment B

Adjusted Transmission Related Taxes and Fees
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Calendar Year 2007

		CL&P	PSNH	WMECO	HWP	HP&E	TOTAL	Reference
1	CT Gross Earnings Tax	4,868,640	-	-	-	-	4,868,640	FF1 p 262 FN
2	CT Excise Tax	31,309	2,610	1,541	-	24	35,484	
3	NH Excise Tax		-	-	-	-	-	
4	Fed. Excise Tax	-	-	529	-	-	529	
5	Mass. Excise Tax	-	-	1	-	-	1	
6	Corporation Business Tax	-	-	3,709	-	-	3,709	
7	MA Sales Tax	-	-	1,110	-	-	1,110	
8	CT Sales Tax	-	827	408	-	-	1,235	
9	NH Business Enterprise Tax	731	47,577	151	-	-	48,459	
10	NY Business Franchise Tax	-	-	-	-	-	-	
11	TOTAL (sum of lines 1 to 10)	4,900,680	51,014	7,449	-	24	4,959,167	To Total RR Wksht 1
12	Pre-97 %	31.4873%	35.6829%	50.3451%	53.3171%	91.9028%		w/s 5A
13	Total Pre-97 Related Exp. (line 11x 12)	1,543,092	18,203	3,750	-	22	1,565,067	To w/s 1A
14	Post-96 %	49.5936%	50.4856%	37.7221%	25.2363%	3.5580%		w/s 5B
15	Total Post-96 Related Exp. (line 11 x 14)	2,430,424	25,755	2,810	-	1	2,458,990	To w/s 1B

Attachment C

Adjusted Short Term Through and Out Revenues
Used in the development of 2007 PTF Revenue Requirements
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects

		CL&P	**PSNH**	**WMECO**	**HWP**	**HP&E**	**TOTAL**	**Reference**
1	2007 Through and Out Revenues	1,456,525	279,197	148,688	414	831	1,885,655	FF1 pg 328.1 - 330.1
2	Less: LT Revs	-	-	-	-	-	-	
3	ST T/O Revenues (Line 1-3)	1,456,525	279,197	148,688	414	831	1,885,655	
4	RTO ROE Adjustm.	44,283	10,686	5,981	72	30	61,052	
5	NET ST T/O Revs.	1,500,808	289,883	154,669	486	861	1,946,707	
6	Pre-1997 PTF Plant	394,346,801	94,756,037	63,415,636	817,677	1,311,855	554,648,006	
7	Post-1996 PTF Plant	621,111,023	134,064,671	47,515,433	387,026	50,788	803,128,941	Attachment A
8	Total PTF Plant	1,015,457,824	228,820,708	110,931,069	1,204,703	1,362,643	1,357,776,947	
9	Ratio of Pre to Total (Line 6 / 8)	38.83%	41.41%	57.17%	67.87%	96.27%		
10	Ratio of Post to Total (Line 7 / 8)	61.17%	58.59%	42.83%	32.13%	3.73%		
		100.00%	100.00%	100.00%	100.00%	100.00%		
	Revenue Credits Allocated to Pre-1997 and Post-1996 Revenue Requirements:							
11	Pre-1997 Revenue Credit (line 5 * 9)	582,764	120,041	88,424	330	829	792,388	to w/s 1A
12	Post-1996 Revenue Credit (line 5 * 10)	918,044	169,842	66,245	156	32	1,154,319	to w/s 1B
13	Total Revenue Credit (line 12+13)	1,500,808	289,883	154,669	486	861	1,946,707	

Attachement D

Northeast Utilites Systems Companies
Adjusted Capitilization
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Calendar Year 2007- Year End

Line No.	**Long Term Debt**	**CLP Year End**	**PSNH Year End**	**WMECO Year End**	**HWP Year End**	**HP&E Year End**	**Reference**
1	Outstanding Bonds (A/C 221 & 224)	1,790,808,737	577,285,000	249,224,829	-	-	FF1 page 257 ln 33
2	Premium on LTD (225)	-	-	(541,390)	-	-	FF1 page 112 ln. 22
3	Discount on LTD (226)	3,891,661	(287,723)	-	-	-	FF1 page 112 ln. 23
4	Debt Expense (181)	17,533,745	7,552,955	2,131,414	-	-	FF1 page 111 ln. 69
5	Gain on Reacquired Debt (257)	-	-	-	-	-	FF1 page 113 ln. 61
6	**Total LTD (Year End) line 1+2-3-4+5)**	**1,769,383,331**	**570,019,768**	**246,552,025**	-	-	
7	**Total LTD (Beginning of Year / End of Year Average)**	**1,521,963,667**	**534,917,134**	**226,897,175**	-	-	(Line 6 + prior YE capitalization) / 2
8	Annual Amort of Prem Disc. & Exp. (A/C 428 minus A/C 429)	1,186,180	736,937	186,838	-	-	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 207)	102,966,324	27,460,135	12,472,300	-	-	FF1 page 257 ln. 33
11	**Total Annual Cost (line 8-9+10)**	104,152,504	**28,197,072**	**12,659,138**	**-**	-	
12	**LTD Cost of Capital (line 11/7)**	**6.84%**	**5.27%**	**5.58%**	**-**	**-**	
	Preferred Stock						
13	Outstanding Stock (204)	116,200,000	-	-	-	-	FF1 page 112 ln. 3
14	Premium on PS (207)	820,027	-	-	-	-	G/L
15	Discount on PS (213)						
16	Unamortized Issue Expense (213)	506,435	-	-	-	-	FF1 page 112 ln. 10
17	**Net Proceeds (line 13+14-15-16)**	**116,513,592**	**-**	**-**	**-**	**-**	
18	Issue Expense Amortization (A/C 214)	140,580	-	-	-	-	FF1 page 112, ln. 10 (diff. in py & cy)
19	Dividend (A/C 437)	5,558,610	-	-	-	-	FF1 page 118 ln. 29
20	**Annual Expense (line 18+19)**	5,699,190	**-**	**-**	**-**	**-**	
21	**PS Cost of Capital (line 20/17)**	**4.89%**	**-**	**-**	**-**	**-**	
22	Proprietary Capital	1,958,450,779	537,866,645	243,250,049	15,087,838	378,220	FF1 page 112 ln. 16
23	**Common Equity (line 22-17)**	1,841,937,187	537,866,645	243,250,049	15,087,838	378,220	

Adjusted 2007 AFUDC Equity Amortization in Depreciation

To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects

PRE-97

	a	b	c	d	e	f	g
	Transmission	PTF Allocator	Transmission PTF level	General Transmission	PTF Allocator	General PTF level	Total at PTF level
			(a*b)			(d*e)	(c+f)
CL&P	1,269,803	31.4873%	399,827	38,047	31.4873%	11,980	411,807
PSNH	125,290	35.6829%	44,707	7,440	35.6829%	2,655	47,362
WMECO	29,104	50.3451%	14,652	1,207	50.3451%	608	15,260
HWP	0	53.3171%	0	0	53.3171%	0	0
HP&E	0	91.9028%	0	0	91.9028%	0	0
	1,424,197		459,186	46,694		15,243	474,429

Adjusted 2007 AFUDC Equity Amortization in Depreciation

To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects

POST-96

	a	b	c	d	e	f	g
	Transmission	PTF Allocator	Transmission PTF level	General Transmission	PTF Allocator	General PTF level	Total at PTF level
			(a*b)			(d*e)	(c+f)
CL&P	1,269,803	49.5936%	629,741	38,047	49.5936%	18,869	648,610
PSNH	125,290	50.4856%	63,253	7,440	50.4856%	3,756	67,009
WMECO	29,104	37.7221%	10,979	1,207	37.7221%	455	11,434
HWP	0	25.2363%	0	0	25.2363%	0	0
HP&E	0	3.5580%	0	0	3.5580%	0	0
	1,424,197		703,973	46,694		23,080	727,053

Note: This worksheet represents the "C" component of the Federal & State Income Tax Formula.

Exhibit 3

Adjusted 2008 PTF Revenue Requirements To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects

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

Submitted on: 18-May-11

Revenue Requirements for (year): June 1, 2009 - May 31, 2010

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

	Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	= -	(a)	-	(g)
Total of Attachment F - Section J - Support Revenue	-	(b)	-	(h)
Total of Attachment F - Section K - Support Expense	-	(c)	-	(i)
Total of Attachment F - Section (L through O)	-	(d)	-	(j)
Sub Total - Sum (A through I) - J + K + (L through O)	-	(e)=(a)-(b)+(c)+(d)	-	(k)=(g)-(h)-(i)-(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	-	(f)	$ -	(l)
Annual True-up (per Attachment C to Attachment F Implementation Rule)	($2,960,347)	(m)	$ 49,140,917	(n)
Adjusted Sub Total (Sub Total + True-up)		(o) = (e)+(f)+(m)		(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)				(q) = (o) + (p)

Note: This revised PTO Annual Transmission Revenue Requirements sheet dated May 18, 2011 only reflects the revised annual true-up as a result of ISO-NE Final Schedule 12C determinations for the Middletown-Norwalk and Glenbrook Cables Projects. (see Attachment K for the incremental refund)

Northeast Utilities System Companies'
Adjusted Annual Revenue Requirements of PTF Facilities for costs in 2008
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
for Rates billed June 1, 2009 - May 31, 2010
Pre-1997

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	CL&P	PSNH	WMECO	HWP	HP&E	Total	Reference
1	Transmission Plant	(A)(1)(a)	393,474,986	93,530,251	66,478,298	-	-	553,483,535	w/s 3A line 1
2	General Plant	(A)(1)(b)	3,928,679	4,205,069	2,073,934	-	-	10,207,682	w/s 3A line 2
3	Plant Held For Future Use	(A)(1)(c)	382,543	1,063,873	464,839	-	-	1,911,255	w/s 3A line 4
4	Total Plant (Lines 1+2+3)		397,786,208	98,799,193	69,017,071	-	-	565,602,472	
5	Accumulated Depreciation	(A)(1)(d)	54,485,752	24,451,018	23,127,827	-	-	102,064,597	w/s 3A line 7
6	Accumulated Deferred Income Taxes	(A)(1)(e)	15,984,058	10,535,300	9,524,595	-	-	36,043,953	w/s 3A line 10
7	Loss On Reacquired Debt	(A)(1)(f)	671,307	355,996	38,122	-	-	1,065,425	w/s 3A line 11
8	Other Regulatory Assets	(A)(1)(g)	3,708,948	521,504	3,997,834	-	-	8,228,286	w/s 3A line 15
9	Net Investment (Line 4-5-6+7+8)		331,696,653	64,690,375	40,400,605	-	-	436,787,633	
10	Prepayments	(A)(1)(h)	2,651,250	2,748,531	1,560,823	-	-	6,960,604	w/s 3A line 16
11	Materials & Supplies	(A)(1)(i)	2,481,294	2,242,498	355,609	-	-	5,079,401	w/s 3A line 17
12	Cash Working Capital	(A)(1)(j)	1,350,076	577,604	541,214	1,563	-	2,470,457	w/s 3A line 24
13	Total Investment Base (Line 9+10+11+12)		338,179,273	70,259,008	42,858,251	1,563	-	451,298,095	
II.	REVENUE REQUIREMENTS								
14	Investment Return and Income Taxes	(A)	43,722,454	8,667,678	5,291,220	309	-	57,681,661	w/s 2A
15	Depreciation Expense	(B)	6,205,277	1,817,679	1,092,106	-	-	9,115,062	w/s 4A line 3
16	Amortization of Loss on Reacquired Debt	(C)	62,340	39,046	1,215	-	-	102,601	w/s 4A line 4
17	Investment Tax Credit	(D)	(121,489)	(5,711)	(24,311)	-	-	(151,511)	w/s 4A line 5
18	Property Tax Expense	(E)	2,730,717	1,475,304	1,054,663	-	-	5,260,684	w/s 4A line 8
19	Payroll Tax Expense	(F)	31,034	17,020	6,293	-	-	54,347	w/s 4A line 19
20	Operation & Maintenance Expense	(G)	5,406,196	2,350,375	2,091,714	-	-	9,848,285	w/s 4A line 17
21	Administrative & General Expense	(H)	4,946,816	1,979,229	1,857,461	-	-	8,783,506	w/s 4A line 18
22	Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	-	-	
23	Transmission Support Revenue	(J)	(1,424,696)	(795,961)	-	-	-	(2,220,657)	
24	Transmission Support Expense	(K)	1,872,293	1,087,191	380,538	12,506	-	3,352,528	
25	Transmission Related Expense from Generators	(L)	-	-	-	-	-	-	
26	Transmission Related Taxes and Fees Charge	(M)	1,749,927	21,946	(11,713)	-	-	1,760,160	Attachment B line 13
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(288,806)	(92,864)	(68,044)	-	-	(449,714)	Attachment C line 11
28	Transmission Rents Received from Electric Property	(O)	(3,579,947)	(746,000)	(138,567)	-	-	(4,464,514)	
29	Total Revenue Requirements (Line 14 thru 28)		61,312,116	15,814,932	11,532,575	12,815	-	88,672,438	

Pre 97 - at 11.64%

Worksheet 1B

Northeast Utilities System Companies'
Adjusted Annual Revenue Requirements of PTF Facilities for costs in 2008
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
for Rates billed June 1, 2009 - May 31, 2010
Post - 1996

Line No.		Attachment F Reference	CL&P	PSNH	WMECO	HWP	HP&E	Total	Reference
	I. INVESTMENT BASE	*Section:*							
1	Transmission Plant	(A)(1)(a)	1,757,732,529	212,097,291	65,847,158	-	-	2,035,676,978	w/s 3A line 1
2	General Plant	(A)(1)(b)	17,550,225	9,535,774	2,054,247	-	-	29,140,246	w/s 3A line 2
3	Plant Held For Future Use	(A)(1)(c)	1,708,900	2,412,530	460,426	-	-	4,581,856	w/s 3A line 4
4	Total Plant (Lines 1+2+3)		1,776,991,654	224,045,595	68,361,831	-	-	2,069,399,080	
5	Accumulated Depreciation	(A)(1)(d)	243,399,144	55,447,220	22,908,287	-	-	321,754,651	w/s 3A line 7
6	Accumulated Deferred Income Taxes	(A)(1)(e)	71,404,098	23,890,747	9,434,184	-	-	104,729,029	w/s 3A line 10
7	Loss On Reacquired Debt	(A)(1)(f)	2,998,867	807,287	37,760	-	-	3,843,914	w/s 3A line 11
8	Other Regulatory Assets	(A)(1)(g)	16,568,639	1,182,607	3,959,885	-	-	21,711,131	w/s 3A line 15
9	Net Investment (Line 4-5-6+7+8)		1,481,755,918	146,697,522	40,017,005	-	-	1,668,470,445	
10	Prepayments	(A)(1)(h)	11,843,685	6,232,803	1,546,007	-	-	19,622,495	w/s 3A line 16
11	Materials & Supplies	(A)(1)(i)	11,084,454	5,085,280	352,234	-	-	16,521,968	w/s 3A line 17
12	Cash Working Capital	(A)(1)(j)	5,781,131	1,227,272	488,961	-	-	7,497,364	w/s 3A line 24
13	Total Investment Base (Line 9+10+11+12)		1,510,465,188	159,242,877	42,404,207	-	-	1,712,112,272	
II.	REVENUE REQUIREMENTS								
14	Investment Return and Income Taxes	(A)	195,284,872	19,645,396	5,235,151	-	-	220,165,419	w/s 2A
15	Depreciation Expense	(B)	27,720,259	4,121,924	1,081,740	-	-	32,923,923	w/s 4A line 3
16	Amortization of Loss on Reacquired Debt	(C)	278,488	88,543	1,203	-	-	368,234	w/s 4A line 4
17	Investment Tax Credit	(D)	(542,718)	(12,951)	(24,081)	-	-	(579,750)	w/s 4A line 5
18	Property Tax Expense	(E)	12,198,679	3,345,525	1,044,652	-	-	16,588,856	w/s 4A line 8
19	Payroll Tax Expense	(F)	138,635	38,595	6,233	-	-	183,463	w/s 4A line 19
20	Operation & Maintenance Expense	(G)	24,150,598	5,329,911	2,071,860	-	-	31,552,369	w/s 4A line 17
21	Administrative & General Expense	(H)	22,098,450	4,488,269	1,839,829	-	-	28,426,548	w/s 4A line 18
22	Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	-	-	
23	Transmission Related Expense from Generators	(L)	-	-	-	-	-	-	
24	Transmission Related Taxes and Fees Charge	(M)	7,817,287	49,767	(11,602)	-	-	7,855,452	Attachment B line 15
25	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(1,290,233)	(210,614)	(67,394)	-	-	(1,568,241)	Attachment C line 12
26	Total Revenue Requirements (Line 14 thru 25)		287,854,317	36,884,365	11,177,591	-	-	335,916,273	

Post 96 - at 11.64%

Northeast Utilities System Companies'

Adjusted Annual Revenue Requirements of post-2003 PTF Incremental Return for costs in 2008
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
for Rates billed June 1, 2009 - May 31, 2010

Line	I. INVESTMENT BASE	CL&P	PSNH	WMECO	Total	Reference
1	Transmission Plant	$ 1,569,290,907	$ 126,352,305	$ 12,323,752	$ 1,707,966,964	Attachment A1
2	Accumulated Depreciation	$ 35,982,485	$ 4,432,911	$ 830,086	$ 41,245,482	↓
3	Accumulated Deferred Income Taxes	$ 34,632,866	$ 5,972,534	$ 1,267,538	$ 41,872,938	
4	Net Investment (Line 1-2-3)	$ 1,498,675,556	$ 115,946,860	$ 10,226,128	$ 1,624,848,544	
	II. INCREMENTAL RETURN					
5	Incremental Revenue Requirements	$ 12,462,986	$ 935,761	$ 82,449	$ 13,481,196	w/s 2A

Northeast Utilities System Companies'

Adjusted Annual Revenue Requirements of Incremental Return For M-N Advance Technology

To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects

for Rates billed June 1, 2009 - May 31, 2010

Line	I. INVESTMENT BASE	CL&P	Reference
1	Transmission Plant	$ 401,338,039	Attachment A1
2	Accumulated Depreciation	$ 1,749,083	↓
3	Accumulated Deferred Income Taxes	$ 589,910	
4	Net Investment (Line 1-2-3)	$ 398,999,046	
	II. INCREMENTAL RETURN		
5	Incremental Revenue Requirements	$ 1,526,331	w/s 2A

Northeast Utilities System Companies'
Adjusted Transmission Revenue Requirements of PTF Facilities
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Year 2008 True-up
Pre-97 and Post-1996

Line	I. ANNUAL TRUE-UP	PRE-97	POST-96	TOTAL	Reference
1	True-up 2008 Actual Annual RR @ 11.64% ROE	89,372,177	361,712,847	451,085,024	2008 ATRR
2	Adjusted 2008 True-up for MN/GB 12-C decsion	88,672,438	350,923,800	439,596,238	w/s 1A, 1B, 1C, 1D
3	Total Rate Year Surcharge/(Refund) (Line 2 - 1)	(699,739)	(10,789,047)	(11,488,786)	

Northeast Utilities System Companies'
FERC Interest Calculation associated with Surcharge / (Refund)
Adjusted Transmission Revenue Requirements of PTF Facilities
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
PRE-97 / Post 96

	Surcharge / (Refund)
Pre	(699,739)
Post	($10,789,047)

Initial Billing Period	Balance Pre 97	Balance Post 96	FERC Monthly Interest Rate	Interest Pre 97	Interest Post 96
June 2008	$ (699,739)	$ (10,789,047)	0.56%	$ (3,919)	$ (60,419)
July 2008	$ (703,658)	$ (10,849,466)	0.45%	$ (3,166)	$ (48,823)
August 2008	$ (703,658)	$ (10,849,466)	0.45%	$ (3,166)	$ (48,823)
September 2008	$ (703,658)	$ (10,849,466)	0.44%	$ (3,096)	$ (47,738)
October 2008	$ (713,086)	$ (10,994,850)	0.42%	$ (2,995)	$ (46,178)
November 2008	$ (713,086)	$ (10,994,850)	0.41%	$ (2,924)	$ (45,079)
December 2008	$ (713,086)	$ (10,994,850)	0.42%	$ (2,995)	$ (46,178)
January 2009	$ (722,000)	$ (11,132,285)	0.38%	$ (2,744)	$ (42,303)
February 2009	$ (722,000)	$ (11,132,285)	0.34%	$ (2,455)	$ (37,850)
March 2009	$ (722,000)	$ (11,132,285)	0.38%	$ (2,744)	$ (42,303)
April 2009	$ (729,943)	$ (11,254,741)	0.28%	$ (2,044)	$ (31,513)
May 2009	$ (729,943)	$ (11,254,741)	0.29%	$ (2,117)	$ (32,639)
June 2009	$ (729,943)	$ (11,254,741)	0.28%	$ (1,799)	$ (23,305)

Worksheet 1E

Initial Billing Period	Balance Pre 97	Balance Post 96	FERC Monthly Interest Rate	Interest Pre 97	Interest Post 96
July 2009	$ (735,903)	$ (11,342,198)	0.28%	$ (1,804)	$ (23,370)
August 2009	$ (735,903)	$ (11,342,198)	0.28%	$ (1,804)	$ (23,370)
September 2009	$ (735,903)	$ (11,342,198)	0.27%	$ (1,740)	$ (22,535)
October 2009	$ (741,251)	$ (11,411,473)	0.28%	$ (1,819)	$ (23,564)
November 2009	$ (741,251)	$ (11,411,473)	0.27%	$ (1,754)	$ (22,722)
December 2009	$ (741,251)	$ (11,411,473)	0.28%	$ (1,819)	$ (23,564)
January 2010	$ (746,643)	$ (11,481,323)	0.28%	$ (1,835)	$ (23,759)
February 2010	$ (746,643)	$ (11,481,323)	0.25%	$ (1,638)	$ (21,214)
March 2010	$ (746,643)	$ (11,481,323)	0.28%	$ (1,835)	$ (23,759)
April 2010	$ (751,951)	$ (11,550,055)	0.27%	$ (1,783)	$ (23,096)
May 2010	$ (751,951)	$ (11,550,055)	0.28%	$ (1,849)	$ (23,952)
June 2010	$ (751,951)	$ (11,550,055)	0.27%	$ (1,783)	$ (23,096)
July 2010	$ (757,366)	$ (11,620,199)	0.28%	$ (1,865)	$ (24,148)
August 2010	$ (757,366)	$ (11,620,199)	0.28%	$ (1,865)	$ (24,148)
September 2010	$ (757,366)	$ (11,620,199)	0.27%	$ (1,798)	$ (23,286)
October 2010	$ (762,894)	$ (11,691,781)	0.28%	$ (1,880)	$ (24,349)
November 2010	$ (762,894)	$ (11,691,781)	0.27%	$ (1,813)	$ (23,479)
December 2010	$ (762,894)	$ (11,691,781)	0.28%	$ (1,880)	$ (24,349)
January 2011	$ (768,467)	$ (11,763,958)	0.28%	$ (1,896)	$ (24,551)
February 2011	$ (768,467)	$ (11,763,958)	0.25%	$ (1,693)	$ (21,920)
March 2011	$ (768,467)	$ (11,763,958)	0.28%	$ (1,896)	$ (24,551)
April 2011	$ (773,952)	$ (11,834,980)	0.27%	$ (1,843)	$ (23,866)
May 2011	$ (773,952)	$ (11,834,980)	0.28%	$ (1,911)	$ (24,750)
	Total Surcharge/(Refund)			**$ (777,706)**	**$ (11,883,596)**

	Interest	Principal	Total (check)	variance
Pre 97	$ (77,967)	$ (699,739)	$ (777,706)	$ -
Post 96	$ (1,094,549)	$ (10,789,047)	$ (11,883,596)	$ -
	$ (1,172,516)	$ (11,488,786)	$ (12,661,302)	$ -

Worksheet 2A

Connecticut Light & Power Company (CL&P)
Adjusted Investment Return and Income Taxes
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Pre 97
for Rates billed June 1, 2009 - May 31, 2010

	CAPITALIZATION 12/31/2008	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 2,006,016,791	47.20%	6.34%	2.99%	
PREFERRED STOCK	$ 116,564,236	2.74%	4.81%	0.13%	0.13%
COMMON EQUITY	$ 2,127,875,417	50.06%	11.64%	5.83%	5.83%
TOTAL INVESTMENT RETURN	$ 4,250,456,444	100.00%		8.95%	5.96%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.08950

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) x Federal Income Tax Rate)

(1 - Federal Income Tax Rate)

= 5.9600% +((121,489) + 254,584) / 338,179,273) x 35.00%)

(1 - 0.35)

= 0.0323042

(c) State Income Tax = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate

(1 - State Income tax Rate)

= 0.0596 +((121,489) + 254,584) / 338,179,273) + 0.0323042)* 0.075

(1 - 0.075)

= 0.0074836

(a)+(b)+(c) Cost of Capital Rate = 0.1292878

	Pre-1997 PTF	
INVESTMENT BASE	338,179,273	From Worksheet 1, line 13
x Cost of Capital Rate	0.1292878	
= Investment Return and Income Taxes	$ 43,722,454	From Worksheet 1, line 14

Worksheet 2A

Connecticut Light & Power Company (CL&P)
Adjusted Investment Return and Income Taxes
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
POST-96
for Rates billed June 1, 2009 - May 31, 2010

	CAPITALIZATION 12/31/2008	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 2,006,016,791	47.20%	6.34%	2.99%	
PREFERRED STOCK	$ 116,564,236	2.74%	4.81%	0.13%	0.13%
COMMON EQUITY	$ 2,127,875,417	50.06%	11.64%	5.83%	5.83%
TOTAL INVESTMENT RETURN	$ 4,250,456,444	100.00%		8.95%	5.96%

Cost of Capital Rate=

(a) Weighted Cost of Capital	=	0.08950										
				PTF Inv.		Eq. AFUDC						
(b) Federal Income Tax	= (	R.O.E. +	(	(Tax Credit	+	of Deprec. Exp.	) /	PTF Inv. Base)		x	Federal Income Tax Rate)	
						(1 - Federal Income Tax Rate)						
	=	5.9600%	+(	(542,718)	+	1,137,278	) /	1,510,465,188	)	x	35.00%)	
					(	1	-	0.35)				
	=	0.0323043										
				PTF Inv.		Eq. AFUDC						
(c) State Income Tax	=	R.O.E. +	(	(Tax Credit	+	of Deprec. Exp.	) /	PTF Inv. Base)		+	Federal Income Tax)*State Income Tax Rate	
						(1 - State Income tax Rate)						
	=	0.0596	+(	(542,718)	+	1,137,278	) /	1,510,465,188	)	+	0.0323043	)* 0.075
					(	1	-	0.075)				
	=	0.0074836										
(a)+(b)+(c) Cost of Capital Rate	=	12.9288%										

	Post - 1996 PTF	
INVESTMENT BASE	1,510,465,188	From Worksheet 1, line 13
x Cost of Capital Rate	0.1292879	
= Investment Return and Income Taxes	$ 195,284,872	From Worksheet 1, line 14

Connecticut Light & Power Company (CL&P)
Adjusted Investment Return and Income Taxes
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Post 2003
Incremental ROE Adder fro RSP Projects

	CAPITALIZATION 12/31/2008	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 2,006,016,791	47.20%	#N/A		
PREFERRED STOCK	116,564,236	2.74%			
COMMON EQUITY	2,127,875,417	50.06%	1.00%	0.50%	0.50%
TOTAL INVESTMENT RETURN	$ 4,250,456,444	100.00%		0.50%	0.50%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0050

(b) Federal Income Tax = (R.O.E. + ((PTF Inv. Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

= (0.0050 + ((0 + 0) / 1,498,675,556) x 0.35)
(1 - 0.35)

= 0.0026923

(c) State Income Tax = (R.O.E. + ((PTF Inv. Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)* State Income Tax Rate
(1 - State Income Tax Rate)

= (0.0050 + ((0 + 0) / 1,498,675,556) + 0.0026923)* 0.075
(1 - 0.075)

= 0.0006237

(a)+(b)+(c) Cost of Capital Rate = 0.0083160

	(post-2003 PTF)	
INVESTMENT BASE	$ 1,498,675,556	From Worksheet 1 Line 4
x Cost of Capital Rate	0.0083160	
= Investment Return and Income Taxes	12,462,986	To Worksheet 1a Line 5

Worksheet 2A M-N Adv Tech

Connecticut Light & Power Company (CL&P)
Adjusted Investment Return and Income Taxes
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
MN Adv Tech
Incremental ROE Adder for MN Adv Tech Project

	CAPITALIZATION 12/31/2008	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 2,006,016,791	47.20%	#N/A		
PREFERRED STOCK	116,564,236	2.74%			
COMMON EQUITY	2,127,875,417	50.06%	0.46%	0.23%	0.23%
TOTAL INVESTMENT RETURN	$ 4,250,456,444	100.00%		0.23%	0.23%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0023

(b) Federal Income Tax

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

$$= \frac{\left(0.0023 + \left(\left(0 + 0 \right) / 398{,}999{,}046 \right) \times 0.35 \right)}{\left(1 - 0.35 \right)}$$

$$= 0.0012385$$

(c) State Income Tax

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

$$= \frac{\left(0.0023 + \left(\left(0 + 0 \right) / 398{,}999{,}046 \right) + 0.0012385 \right) * 0.075}{\left(1 - 0.075 \right)}$$

$$= 0.0002869$$

(a)+(b)+(c) Cost of Capital Rate = 0.0038254

	(MN Adv Tech)	
INVESTMENT BASE	$ 398,999,046	From Worksheet 1 Line 4
x Cost of Capital Rate	0.0038254	
= Investment Return and Income Taxes	1,526,331	To Worksheet 1a Line 5

Connecticut Light & Power Company (CL&P)
Adjusted Rate Base Items
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Calendar Year 2008

					PRE-97 PTF		POST-96 PTF		
Line No.		(1) Total	(2) Wage/Plant Allocation Factors (a)	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	(6) PTF Allocation Factor (b)	(7) = (3)*(6) PTF Allocated	Reference
	Transmission Plant								
1	Transmission Plant					393,474,986		1,757,732,529	Attachment A
2	General Plant	23,879,937		23,879,937	16.4518%	3,928,679	73.4936%	17,550,225	FF1 page 206-207 ln. 99, footnote
3	Total (line 1+2)	23,879,937		23,879,937		397,403,665		1,775,282,754	
4	Transmission Plant Held for Future Use	2,325,237 (c)		2,325,237	16.4518%	382,543	73.4936%	1,708,900	(c)
	Transmission Accumulated Depreciation (b)								
5	Transmission Accum. Depreciation	322,960,867		322,960,867	16.4518%	53,132,876	73.4936%	237,355,568	FF1 page 219 ln. 25
6	General Plant Accum.Depreciation	8,223,269		8,223,269	16.4518%	1,352,876	73.4936%	6,043,576	FF1 page 219 ln. 28, footnote
7	Total (line 5+6)	331,184,136		331,184,136		54,485,752		243,399,144	
	Transmission Accumulated Deferred Taxes								
8	Accumulated Deferred Taxes (281 to 283)	(147,607,058)		(147,607,058)	16.4518%	(24,284,018)	73.4936%	(108,481,741)	FF1 page 274 ln. 9 & 276 ln. 19 footnote
9	Accumulated Deferred Taxes (190)	50,450,166 (d)		50,450,166	16.4518%	8,299,960	73.4936%	37,077,643	(d)
10	Total (line 8+9)	(97,156,892)		(97,156,892)		(15,984,058)		(71,404,098)	
11	Transmission loss on Reacquired Debt	4,080,446		4,080,446	16.4518%	671,307	73.4936%	2,998,867	FF1 page 111 ln. 81, footnote
	Other Regulatory Assets								
12	FAS 106	-		-	16.4518%	-	73.4936%	-	FF1 page 232
13	FAS 109	26,512,991		26,512,991	16.4518%	4,361,864	73.4936%	19,485,352	FF1 page 232 ln. 10, footnote
14	Other Regulatory Liabilities (254.DK)	(3,968,663)		(3,968,663)	16.4518%	(652,916)	73.4936%	(2,916,713)	FF1 page 278 ln. 5, footnote
15	Total (line 12+13+14)	22,544,328		22,544,328		3,708,948		16,568,639	
16	Transmission Prepayments (165)	16,115,260		16,115,260	16.4518%	2,651,250	73.4936%	11,843,685	FF1 page 110 ln. 57, footnote
17	Transmission Materials and Supplies	15,082,203		15,082,203	16.4518%	2,481,294	73.4936%	11,084,454	FF1 page 227 ln. 8
18	Cash Working Capital								
19	Operation & Maintenance Expense					5,406,196		24,150,598	w/s 4a, Line 17
20	Administrative & General Expense					4,946,816		22,098,450	w/s 4a, Line 18
21	Transmission Support Expense					447,597		-	w/s 7
22	Subtotal (line 19+20+21)					10,800,609		46,249,048	
23						0.125		0.125	x 45 / 360
24	Total (line 22 * line 23)					1,350,076		5,781,131	

(a) All B/S items functionalized per FERC Form 1; therefore, no need to use Wage/Plant Allocation Factor (column 2)
(b) Worksheet 5 line 3

(c)	Account 105	35,014,450	FF1 page 214 (py ln. 29 & cy ln.14)
	Less Third Underground Conduit Duct	32,689,213	
		2,325,237	

(d)	Account 190	84,732,144	FF1 page 234 ln. 18, footnote
	Less Reserve for Disputed Transactions	34,281,978	
	Total Account 190	50,450,166	

Worksheet 4A

Connecticut Light & Power Company (CL&P)
Adjusted Expense Items
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Calendar Year 2008

					PRE-97 PTF		POST-96 PTF		
Line No.		(1) Total	(2) Wage/Plant Allocation Factors (a)	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) Pre-97 PTF Allocated	(6) PTF Allocation Factor (b)	(7) = (3)*(6) Post-96 PTF Allocated	Reference
	Depreciation Expense								
1	Transmission Depreciation	36,039,996		36,039,996	16.4518%	5,929,228	73.4936%	26,487,091	FF 1 page 336 ln. 7
2	General Depreciation	1,677,926		1,677,926	16.4518%	276,049	73.4936%	1,233,168	FF1 page 336 ln. 10, footnote
3	Total (line 1+2)	37,717,922		37,717,922		6,205,277		27,720,259	
4	Amortization of Loss on Reacquired Debt	378,928		378,928	16.4518%	62,340	73.4936%	278,488	FF1 page 114, ln. 64, footnote
5	Amortization of Investment Tax Credits	738,456		738,456	16.4518%	121,489	73.4936%	542,718	FF1 page 266 ln. 8, footnote - difference of PY-CY
	Property Taxes								
6	Transmission Property Taxes	16,598,288		16,598,288	16.4518%	2,730,717	73.4936%	12,198,679	FF1 page 262 ln. 25, footnote
7	General Property Taxes (c)	-		-	16.4518%	-	73.4936%	-	
8	Total (line 6+7)	16,598,288		16,598,288		2,730,717		12,198,679	
	Transmission Operation and Maintenance								
9	Operation and Maintenance	149,433,320		149,433,320	16.4518%	24,584,471	73.4936%	109,823,926	FF1 page 321 ln. 112
10	Transmission of Electricity by Others - #565	102,723,436		102,723,436	16.4518%	16,899,854	73.4936%	75,495,151	FF1 page 321 ln. 96
11	Load Dispatching - #561	-		-	16.4518%	-	73.4936%	-	FF1 page 321 ln. 84
12	Account 561.1	2,802,058		2,802,058	16.4518%	460,989	73.4936%	2,059,333	FF1 page 321 ln. 85
13	Account 561.2	4,887,770		4,887,770	16.4518%	804,126	73.4936%	3,592,198	FF1 page 321 ln. 86
14	Account 561.3	1,610,140		1,610,140	16.4518%	264,897	73.4936%	1,183,350	FF1 page 321 ln. 87
15	Account 561.4	4,549,098		4,549,098	16.4518%	748,409	73.4936%	3,343,296	FF1 page 321 ln. 88
16	**Station Expenses & Rents - #562 / #567	-		-		-		-	
17	O&M less lines 10 thru 16	32,860,818		32,860,818	16.4518%	5,406,196	73.4936%	24,150,598	
	Transmission Administrative and General								
18	Administrative and General	30,068,537		30,068,537	16.4518%	4,946,816	73.4936%	22,098,450	FF1 page 320 ln. 197, footnote
19	*Payroll Tax Expense*	*188,635*		188,635	16.4518%	31,034	73.4936%	138,635	
	Federal Unemployment	1,833							FF1 page 262 ln. 20i, footnotes
	FICA	137,676							FF1 page 262 ln. 4i, footnote
	Medicare	39,810							FF1 page 262 ln. 9i, footnote
	CT Unemployment	9,032							FF1 page 262 ln. 15i, footnote
	DC Unemployment	8							FF1 page 262.1 ln. 13i, footnote
	FL Unemployment	-							FF1 page 262.1 ln. 17i, footnote
	GA Unemployment	-							FF1 page 262 & 263 footnote
	MA Unemployment	15							FF1 page 262 ln. 33i, footnote
	MA Universal Health	30							FF1 page 262 ln. 34i, footnote
	NH Unemployment	209							FF1 page 262.1 ln. 3i, footnote
	NJ Unemployment	-							FF1 page 262 & 263 footnote
	NY Unemployment	22							FF1 page 262.1 ln. 9i, footnote
	Total	188,635	To Line 19						

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

(a) All expenses functionalized per FERC Form 1; therefore, no need to use Wage/Plant Allocation Factor (column 2)

(b) Worksheet 5, Line 3

(c) Transmission related general property taxes are included in the Transmission Property tax number footnoted in the FF1

Worksheet 5A

Northeast Utilities System Companies
Adjusted Allocation Factors
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Calendar Year 2008
PRE-1997

Line No.	**PTF Transmission Plant Allocation Factor**	CL&P	PSNH	WMECO	HWP	HP&E	TOTAL	Reference
1	PTF Transmission Investment	393,474,986	93,530,251	66,478,298	-	-	553,483,535	w/s 3A line 1
2	Total Transmission Investment	2,391,681,976	344,000,266	148,445,303	-	-	2,884,127,545	FF1 page 206-207 ln 58
3	Percent Allocation (Line 1 / Line 2)	16.4518%	27.1890%	44.7830%	0.0000%	0.0000%	19.1907%	
	Transmission Wages and Salaries Allocation Factor							
4	Direct Transmission Wages and Salaries	5,708,217	1,976,808	1,052,412	-	-	8,737,437	FF1 page 354 ln 21
5	Affiliated Company Transmission Wages and Salaries	12,261,639	1,262,364	606,375	-	-	14,130,378	w/s 6 line 15
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	17,969,856	3,239,172	1,658,787	-	-	22,867,815	
7	Total Wages and Salaries	98,752,039	73,647,823	20,601,092	-	-	193,000,954	FF1 pg 354 ln 28
8	Administrative and General Wages and Salaries	11,537,111	10,123,934	2,382,378	-	-	24,043,423	FF1 pg 354 ln 27
9	Affiliated Company Wages and Salaries less A&G	76,155,283	21,718,821	11,331,863	-	-	109,205,967	w/s 6 line 30
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	163,370,211	85,242,710	29,550,577	-	-	278,163,498	
11	Percent Allocation (Line 6 / Line 10)	10.9995%	3.7999%	5.6134%	0.0000%	0.0000%	8.2210%	
	Plant Allocation Factor							
12	Total Transmission Investment (Line 2)	2,391,681,976	344,000,266	148,445,303	-	-	2,884,127,545	
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	23,879,937	15,466,068	4,631,074	-	-	43,977,079	w/s 3A line 2
14	*= Revised Numerator (Line 12 + Line 13)*	2,415,561,913	359,466,334	153,076,377	-	-	2,928,104,624	
15	Total Plant in Service	6,189,662,150	2,225,469,883	777,782,290	-	-	9,192,914,323	FF1 206-207 ln 100
16	Percent Allocation (Line 14 / Line 15)	39.0257%	16.1524%	19.6811%	0.0000%	0.0000%	31.8518%	

Worksheet 5B

Northeast Utilities System Companies
Adjusted Allocation Factors
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Calendar Year 2008
POST - 1996

Line No.		CL&P	PSNH	WMECO	HWP	HP&E	TOTAL	Reference
	PTF Transmission Plant Allocation Factor							
1	PTF Transmission Investment	1,757,732,529	212,097,291	65,847,158	-	-	2,035,676,978	w/s 3A line 1
2	Total Transmission Investment	2,391,681,976	344,000,266	148,445,303	-	-	2,884,127,545	FF1 page 206-207 ln 58
3	Percent Allocation (Line 1/Line 2)	73.4936%	61.6561%	44.3579%	0.0000%	0.0000%	70.5821%	
	Transmission Wages and Salaries Allocation Factor							
4	Direct Transmission Wages and Salaries	5,708,217	1,976,808	1,052,412	-	-	8,737,437	FF1 page 354 ln 21
5	Affiliated Company Transmission Wages and Salaries	12,261,639	1,262,364	606,375	-	-	14,130,378	w/s 6 line 15
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	17,969,856	3,239,172	1,658,787	-	-	22,867,815	
7	Total Wages and Salaries	98,752,039	73,647,823	20,601,092	-	-	193,000,954	FF1 pg 354 ln 28
8	Administrative and General Wages and Salaries	11,537,111	10,123,934	2,382,378	-	-	24,043,423	FF1 pg 354 ln 27
9	Affiliated Company Wages and Salaries less A&G	76,155,283	21,718,821	11,331,863	-	-	109,205,967	w/s 6 line 30
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	163,370,211	85,242,710	29,550,577	-	-	278,163,498	
11	Percent Allocation (Line 6/Line 10)	10.9995%	3.7999%	5.6134%	0.0000%	0.0000%	8.2210%	
	Plant Allocation Factor							
12	Total Transmission Investment (line 2)	2,391,681,976	344,000,266	148,445,303	-	-	2,884,127,545	
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	23,879,937	15,466,068	4,631,074	-	-	43,977,079	w/s 3A line 2
14	*= Revised Numerator (Line 12 + Line 13)*	2,415,561,913	359,466,334	153,076,377	-	-	2,928,104,624	
15	Total Plant in Service	6,189,662,150	2,225,469,883	777,782,290	-	-	9,192,914,323	FF1 206-207 ln 100
16	Percent Allocation (Line 14 / Line 15)	39.0257%	16.1524%	19.6811%	0.0000%	0.0000%	31.8518%	

Attachment A

Connecticut Light and Power Company
Substations and Lines
PTF Investment as of 12/31/08 (101 + 106)
REVISED 4/25/11 FOR M-N & G-B Projects FINAL 12C

	350	352	353	354	355	356	357	358	359	361	362	Grand Total
1997	39,442.79	38,745.58	5,984,021.17	112,607.52	118,897.46	4,837,106.76	0.00	0.00	0.00	15,847.98	79,041.58	11,225,710.84
1998	(6,147.32)	55,353.65	463,770.72	0.00	113,374.45	105,664.19	0.00	0.00	0.00	15,932.96	22,385.26	770,333.91
1999	0.00	0.00	631,046.61	28,802.26	26,718.64	6,688.86	0.00	0.00	0.00	9,163.14	32,464.13	734,883.64
2000	0.00	0.00	2,803,643.19	0.00	265,097.29	5,663.06	136,633.03	179,004.16	61,360.97	37,216.59	207,210.62	3,695,828.91
2001	264,948.05	248,123.86	17,756,800.14	0.00	1,357,586.60	35,280.85	0.00	0.00	0.00	0.00	25,116.79	19,687,856.29
2002	0.00	106,572.19	6,261,562.01	184,907.20	1,932,736.37	2,939,424.59	0.00	0.00	0.00	155,467.04	183,182.42	11,763,851.82
2003	(30,877.09)	193,100.24	14,603,683.74	55,332.28	8,919,998.82	2,547,946.34	0.00	0.00	0.00	64,864.29	82,366.19	26,436,414.80
2004	607,291.35	2,002,493.59	58,741,981.26	0.00	2,261,294.57	377,603.79	1,068,563.42	1,191,273.47	18,824.61	7,619.33	337,226.15	66,614,171.53
2005	3,011,400.01	4,577,803.31	77,559,221.87	0.00	3,492,551.70	4,208,029.44	16,440,131.15	9,216,659.97	0.00	159,874.11	130,844.48	118,796,516.04
2006	11,354,553.03	7,324,439.80	80,179,976.31	0.00	19,563,666.39	9,071,998.93	20,612,824.84	68,008,557.02	3,972,661.67	1,024,927.04	952,000.04	222,065,605.07
2007	10,929,883.96	2,734,121.52	90,453,390.65	0.00	82,988,383.35	46,903,437.54	0.00	0.00	29,274.47	18,504.87	123,647.09	234,180,643.46
2008	2,390,551.57	4,201,048.02	212,244,555.09	280,262.52	20,248,618.47	156,954,258.96	398,458,047.95	244,438,885.74	2,508,179.72	36,304.69	0.00	1,041,760,712.74
Post-1996	28,561,046.35	21,481,801.76	567,683,652.75	661,911.78	141,288,924.11	227,993,103.31	436,716,200.39	323,034,380.36	6,590,301.44	1,545,722.04	2,175,484.76	1,757,732,529.06

Attachment A1

CL+P RSP INVESTMENT BY PLANT ACCOUNT AT 12-31-08
REVISED 4-25-11 FOR M-N & G-B Projects FINAL 12C

		Data		
Plant A/C	Year	Sum of Gross Plant2	Sum of Accum Depr2	Sum of Net Plant2
350	2004	423,777.17	26,351.31	397,425.86
	2005	2,350,091.18	116,255.41	2,233,835.77
	2006	11,118,084.14	218,289.35	10,899,794.79
	2007	10,920,088.61	240,114.76	10,679,973.85
	2008	1,470,938.83	575.46	1,470,363.37
350 Total		26,282,979.93	601,586.29	25,681,393.64
352	2004	1,166,407.66	132,707.99	1,033,699.67
	2005	4,449,360.81	401,158.59	4,048,202.22
	2006	7,303,371.66	479,771.13	6,823,600.53
	2007	2,616,640.29	105,319.11	2,511,321.18
	2008	4,058,343.91	55,663.92	4,002,679.99
352 Total		19,594,124.33	1,174,620.74	18,419,503.59
353	2004	54,074,597.23	4,765,623.48	49,308,973.75
	2005	66,879,507.51	4,694,566.25	62,184,941.26
	2006	68,283,250.03	3,509,083.06	64,774,166.97
	2007	62,963,741.68	1,990,834.17	60,972,907.51
	2008	190,028,078.41	2,056,759.39	187,971,319.02
353 Total		442,229,174.85	17,016,866.35	425,212,308.51
355	2004	233,478.02	38,016.79	195,461.23
	2005	2,569,188.47	320,459.73	2,248,728.74
	2006	17,479,843.77	1,541,912.04	15,937,931.73
	2007	75,779,833.47	4,011,436.55	71,768,396.92
	2008	17,931,441.19	322,749.79	17,608,691.40
355 Total		113,993,784.92	6,234,574.90	107,759,210.02
356	2004	163,768.35	21,090.98	142,677.37
	2005	2,682,262.95	270,084.87	2,412,178.08
	2006	5,504,873.34	398,085.51	5,106,787.83
	2007	36,437,313.13	1,589,436.75	34,847,876.37
	2008	156,798,239.25	2,293,100.58	154,505,138.67
356 Total		201,586,457.02	4,571,798.69	197,014,658.32
357	2004	1,068,563.42	29,444.83	1,039,118.59
	2005	16,440,131.15	352,346.21	16,087,784.95
	2006	20,612,824.84	315,554.10	20,297,270.74
	2007	-	-	-
	2008	398,458,047.95	1,219,970.96	397,238,076.99
357 Total		436,579,567.36	1,917,316.10	434,662,251.26
358	2004	1,191,273.47	34,998.24	1,156,275.23
	2005	9,216,659.97	252,118.05	8,964,541.92
	2006	67,785,910.10	1,650,721.81	66,135,188.29
	2007	-	-	-
	2008	244,438,885.74	2,359,295.72	242,079,590.02
358 Total		322,632,729.28	4,297,133.82	318,335,595.45
359	2006	3,928,573.16	149,674.90	3,778,898.27
	2008	2,463,515.80	18,913.39	2,444,602.41
359 Total		6,392,088.96	168,588.29	6,223,500.68
Grand Total		1,569,290,906.65	35,982,485.18	1,533,308,421.48

Attachment A2

CL+P ADVANCED TECHNOLOGY INVESTMENT AT 12-31-08

REVISED 4-25-11 For M-N PROJECT FINAL 12C

Work Order Description	Plant A/c	Work Order Inservice Year	Gross Plant	Accum Depr	Net Plant
MN 345KV SEG1 BESECK SWITCH STATION	35389	2007	214,782.79	6,791.16	207,991.63
MN 345KV SEGMENT 2 EAST DEVON S/S-115KV WORK	35389	2008	228,611.62	2,474.37	226,137.26
MN 345KV SEGMENT 2 EAST DEVON S/S-345KV WORK	35389	2008	155,527.35	1,683.35	153,844.00
MN 345KV SEGMENT 2 EAST DEVON S/S-AUTOS	35389	2008	131,699.72	1,425.45	130,274.27
MN 345KV SEGMENT 2 EAST DEVON S/S-AUTOS	35389	2008	167,348.48	1,811.29	165,537.20
MN 345KV SEGMENT 3 EAST DEVON TO SINGER	357	2008	49,682,159.53	152,113.36	49,530,046.17
MN 345KV SEG 3 ROW EASEMENTS	35002	2007	154,082.53	7,665.59	146,416.94
MN 345KV SEG 3 ROW EASEMENTS	35002	2007	318,714.78	15,856.03	302,858.75
BRIDGEPORT 2006 AQUIRED EASEMENTSSEG 3 MN345K	35002	2006	551,702.94	34,551.81	517,151.13
MN 345KV SEGMENT 4 SINGER TO NORWALK	357	2008	335,052,342.11	1,025,839.81	334,026,502.30
MN 345KV SEGMENT 4 NORWALK SS	35389	2008	132,143.37	1,430.25	130,713.13
MN 345KV SEGMENT 4 NORWALK SS	35389	2008	88,092.22	953.46	87,138.76
MN 345KV SEGMENT 4 NORWALK SS	35389	2008	276,774.02	2,995.65	273,778.37
MN 345KV SEGMENT 4 NORWALK SS_SHUNT REACTORS	35389	2008	6,640,451.72	71,872.59	6,568,579.13
MN 345KV SEG 4 ROW EASEMENTS	35002	2007	832,242.54	41,403.97	790,838.57
MN 345KV SEG 4 ROW EASEMENTS	35002	2007	1,969,149.47	97,964.97	1,871,184.50
MN 345KV SEG 4 ROW EASEMENTS	35002	2007	1,100,725.15	54,760.96	1,045,964.19
FAIRFIELD 2006 AQUIRED EASEMENTS MN345KV SEG4	35002	2006	1,276,433.81	79,939.94	1,196,493.87
WESTPORT 2006 EASEMENTS AQUIRED MN345KV SEG4	35002	2006	1,471,790.40	92,174.64	1,379,615.76
NORWALK 2006 EASEMENTS AQUIRED MN345KV SEG 4	35002	2006	871,657.40	54,589.78	817,067.62
MN 345KV SEG 4 ROW EASEMENT LL 543.01 WESTPOR	35002	2008	21,606.96	784.72	20,822.24
			401,338,038.93	1,749,083.14	399,588,955.79

Attachment B

Adjusted Transmission Related Taxes and Fees
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Calendar Year 2008

		CL&P	PSNH	WMECO	HWP	HP&E	TOTAL	Reference
1	CT Gross Earnings Tax	10,349,970	-	-	-	-	10,349,970	FF1 p 262 FN
2	CT Excise Tax	45,173	2,785	1,743	-	-	49,701	
3	NH Excise Tax	-	7,726	-	-	-	7,726	
4	Fed. Excise Tax	-	-	-	-	-	-	
5	Mass. Excise Tax	3	1	1	-	488	493	
6	Corporation Business Tax	-	-	(30,535)	-	-	(30,535)	
7	MA Sales Tax	-	-	2,017	-	-	2,017	
8	CT Sales Tax	240,386	894	381	-	-	241,661	
9	NH Business Enterprise Tax	1,159	69,311	238	-	-	70,708	
10	NY Business Franchise Tax	-	-	-	-	-	-	
11	TOTAL (sum of lines 1 to 10)	10,636,691	80,717	(26,155)	-	488	10,691,741	To Total RR Wksht 1
12	Pre-97 %	16.4518%	27.1890%	44.7830%	0.0000%	0.0000%		w/s 5A
13	Total Pre-97 Related Exp. (line 11x 12)	1,749,927	21,946	(11,713)	-	-	1,760,160	To w/s 1A
14	Post-96 %	73.4936%	61.6561%	44.3579%	0.0000%	0.0000%		w/s 5B
15	Total Post-96 Related Exp. (line 11 x 14)	7,817,287	49,767	(11,602)	-	-	7,855,452	To w/s 1B

Attachment C

Adjusted Short Term Through and Out Revenues
Used in the development of 2008 PTF Revenue Requirements
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects

		CL&P	PSNH	WMECO	HWP	HP&E	TOTAL	Reference
1	2008 Through and Out Revenues	1,579,039	303,478	135,438	107	1,412	2,019,474	FF1 pg 328.1 - 330.1
2	Less: LT Revs	-	-	-	-	-	-	
3	ST T/O Revenues (Line 1-2)	1,579,039	303,478	135,438	107	1,412	2,019,474	
4	RTO ROE Adjustm.	-	-	-	-	-	-	
5	NET ST T/O Revs.	1,579,039	303,478	135,438	107	1,412	2,019,474	
6	Pre-1997 PTF Plant	393,474,986	93,530,251	66,478,298	-	-	553,483,535	
7	Post-1996 PTF Plant	1,757,732,529	212,097,291	65,847,158	-	-	2,035,676,978	Attachment A
8	Total PTF Plant	2,151,207,515	305,627,542	132,325,456	-	-	2,589,160,513	
9	Ratio of Pre to Total (Line 6 / 8)	18.29%	30.60%	50.24%	0.00%	0.00%		
10	Ratio of Post to Total (Line 7 / 8)	81.71%	69.40%	49.76%	0.00%	0.00%		
		100.00%	100.00%	100.00%	0.00%	0.00%		
	Revenue Credits Allocated to Pre-1997 and Post-1996 Revenue Requirements:							
11	Pre-1997 Revenue Credit (line 5 * 9)	288,806	92,864	68,044	-	-	449,714	to w/s 1A
12	Post-1996 Revenue Credit (line 5 * 10)	1,290,233	210,614	67,394	-	-	1,568,241	to w/s 1B
13	Total Revenue Credit (line 11+12)	1,579,039	303,478	135,438	-	-	2,017,955	

Attachment D

Northeast Utilities Systems Companies
Adjusted Capitalization
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Calendar Year 2008- Year End

Line No.	Long Term Debt	CL&P Year End	PSNH Year End	WMECO Year End	HWP Year End	HP&E Year End	Reference
1	Outstanding Bonds (A/C 221 & 224)	2,028,994,209	687,285,000	249,028,754	-	-	FF1 page 257 ln 33
2	Premium on LTD (225)	-	-	-	-	-	FF1 page 112 ln. 22
3	Discount on LTD (226)	4,323,501	506,349	494,960	-	-	FF1 page 112 ln. 23
4	Debt Expense (181)	18,653,917	7,834,496	1,976,831	-	-	FF1 page 111 ln. 69
5	Gain on Reacquired Debt (257)	-	-	-	-	-	FF1 page 113 ln. 61
6	**Total LTD (Year End) line 1+2-3-4+5)**	**2,006,016,791**	**678,944,155**	**246,556,963**	-	-	
7	**Total LTD (Beginning of Year / End of Year Average)**	**1,887,700,061**	**624,481,962**	**246,554,494**	-	-	(Line 6 + prior YE capitalization) / 2
8	Annual Amort of Prem Disc. & Exp. (A/C 428 minus A/C 429)	1,517,382	915,277	201,013	-	-	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 207)	118,232,051	33,795,926	14,132,411	-	-	FF1 page 257 ln. 33
11	**Total Annual Cost (line 8-9+10)**	**119,749,433**	**34,711,203**	**14,333,424**	**-**	**-**	
12	**LTD Cost of Capital (line 11/7)**	**6.34%**	**5.56%**	**5.81%**	**-**	**-**	
	Preferred Stock						
13	Outstanding Stock (204)	116,200,000	-	-	-	-	FF1 page 112 ln. 3
14	Premium on PS (207)	820,027	-	-	-	-	G/L
15	Discount on PS (213)						
16	Unamortized Issue Expense (213)	455,791	-	-	-	-	FF1 page 112 ln. 10
17	**Net Proceeds (line 13+14-15-16)**	**116,564,236**	**-**	**-**	**-**	**-**	
18	Issue Expense Amortization (A/C 214)	50,644	-	-	-	-	FF1 page 112, ln. 10 (diff. in py & cy)
19	Dividend (A/C 437)	5,558,610	-	-	-	-	FF1 page 118 ln. 25
20	**Annual Expense (line 18+19)**	5,609,254	**-**	**-**	**-**	**-**	
21	**PS Cost of Capital (line 20/17)**	**4.81%**	**-**	**-**	**-**	**-**	
22	Proprietary Capital	2,244,439,653	633,714,855	238,149,803	8,438,823	484,156	FF1 page 112 ln. 16
23	**Common Equity (line 22-17)**	2,127,875,417	633,714,855	238,149,803	8,438,823	484,156	

Adjusted 2008 AFUDC Equity Amortization in Depreciation

To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects

PRE-97

	a	b	c	d	e	f	g
	Transmission	PTF Allocator	Transmission PTF level	General Transmission	PTF Allocator	General PTF level	Total at PTF level
			(a*b)			(d*e)	(c+f)
CL&P	1,509,427	16.4518%	248,328	38,025	16.4518%	6,256	254,584
PSNH	43,740	27.1890%	11,892	5,313	27.1890%	1,445	13,337
WMECO	15,228	44.7830%	6,820	648	44.7830%	290	7,110
HWP	-	0.0000%	-	-	0.0000%	-	-
HP&E	-	0.0000%	-	-	0.0000%	-	-
	1,568,395		267,040	43,986		7,991	275,031

Adjusted 2008 AFUDC Equity Amortization in Depreciation

To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects

POST-96

	a	b	c	d	e	f	g
	Transmission	PTF Allocator	Transmission PTF level	General Transmission	PTF Allocator	General PTF level	Total at PTF level
			(a*b)			(d*e)	(c+f)
CL&P	1,509,427	73.4936%	1,109,332	38,025	73.4936%	27,946	1,137,278
PSNH	43,740	61.6561%	26,968	5,313	61.6561%	3,276	30,244
WMECO	15,228	44.3579%	6,755	648	44.3579%	287	7,042
HWP	-	0.0000%	-	-	0.0000%	-	-
HP&E	-	0.0000%	-	-	0.0000%	-	-
	1,568,395		1,143,055	43,986		31,509	1,174,564

Note: This worksheet represents the "C" component of the Federal & State Income Tax Formula.

Exhibit 4

Adjusted 2009 PTF Revenue Requirements To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects

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

Submitted on: 18-May-11

Revenue Requirements for (year): June 1, 2010 - May 31, 2011

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

		Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	=	-	(a)	-	(g)
Total of Attachment F - Section J - Support Revenue		-	(b)	-	(h)
Total of Attachment F - Section K - Support Expense		-	(c)	-	(i)
Total of Attachment F - Section (L through O)		-	(d)	-	(j)
Sub Total - Sum (A through I) - J + K + (L through O)		-	(e)=(a)-(b)+(c)+(d)	-	(k)=(g)-(h)+(i)+(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)		-	(f)	-	(l)
Annual True-up (per Attachment C to Attachment F Implementation Rule)		3,594,887	(m)	(1,113,684)	(n)
Adjusted Sub Total (Sub Total + True-up)			(o) = (e)+(f)+(m)		(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)					(q) = (o) + (p)

Note: This revised PTO Annual Transmission Revenue Requirements sheet dated May 18, 2011 only reflects the revised annual true-up as a result of ISO-NE Final Schedule 12C determinations for the Middletown-Norwalk and Glenbrook Cables Projects. (see Attachment K for the incremental refund)

Worksheet 1A

Northeast Utilities System Companies'
Adjusted Annual Revenue Requirements of PTF Facilities for costs in 2009
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
for Rates billed June 1, 2010 - May 31, 2011
Pre-1997

Line No.		Attachment F Reference *Section:*	CL&P	PSNH	WMECO	Total	Reference
	I. INVESTMENT BASE						
1	Transmission Plant	(A)(1)(a)	387,837,863	96,744,902	65,630,687	550,213,452	w/s 3A line 1
2	General Plant	(A)(1)(b)	7,908,318	7,386,441	2,404,058	17,698,817	w/s 3A line 2
3	Plant Held For Future Use	(A)(1)(c)	366,222	1,204,503	5,240,803	6,811,528	w/s 3A line 4
4	Total Plant (Lines 1+2+3)		396,112,403	105,335,846	73,275,548	574,723,797	
5	Accumulated Depreciation	(A)(1)(d)	56,802,420	22,171,235	19,999,998	98,973,653	w/s 3A line 7
6	Accumulated Deferred Income Taxes	(A)(1)(e)	24,584,372	13,289,236	9,650,435	47,524,043	w/s 3A line 10
7	Loss On Reacquired Debt	(A)(1)(f)	849,771	465,911	34,994	1,350,676	w/s 3A line 11
8	Other Regulatory Assets	(A)(1)(g)	3,012,177	630,755	60,830	3,703,762	w/s 3A line 15
9	Net Investment (Line 4-5-6+7+8)		318,587,559	70,972,041	43,720,939	433,280,539	
10	Prepayments	(A)(1)(h)	851,000	1,767,821	1,725,380	4,344,201	w/s 3A line 16
11	Materials & Supplies	(A)(1)(i)	2,545,285	775,392	2,029,272	5,349,949	w/s 3A line 17
12	Cash Working Capital	(A)(1)(j)	1,517,674	671,001	457,113	2,645,788	w/s 3A line 24
13	Total Investment Base (Line 9+10+11+12)		323,501,518	74,186,255	47,932,704	445,620,477	
	II. REVENUE REQUIREMENTS						
14	Investment Return and Income Taxes	(A)	41,940,937	8,655,867	5,990,869	56,587,673	w/s 2A
15	Depreciation Expense	(B)	9,054,319	2,110,342	1,145,314	12,309,975	w/s 4A line 3
16	Amortization of Loss on Reacquired Debt	(C)	68,135	41,105	3,219	112,459	w/s 4A line 4
17	Investment Tax Credit	(D)	(108,845)	(3,121)	(19,867)	(131,833)	w/s 4A line 5
18	Property Tax Expense	(E)	3,962,211	1,709,592	1,003,673	6,675,476	w/s 4A line 8
19	Payroll Tax Expense	(F)	81,627	33,450	28,270	143,347	w/s 4A line 19
20	Operation & Maintenance Expense	(G)	5,227,338	2,721,410	1,665,137	9,613,885	w/s 4A line 17
21	Administrative & General Expense	(H)	6,526,023	1,929,058	1,601,005	10,056,086	w/s 4A line 18
22	Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	
23	Transmission Support Revenue	(J)	(1,473,441)	(361,118)	-	(1,834,559)	
24	Transmission Support Expense	(K)	1,861,473	1,078,657	390,766	3,330,896	
25	Transmission Related Expense from Generators	(L)	-	-	-	-	
26	Transmission Related Taxes and Fees Charge	(M)	2,408,827	(14,309)	(29,103)	2,365,415	Attachment B line 14
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(210,884)	(52,691)	(38,593)	(302,168)	Attachment C line 11
28	Transmission Rents Received from Electric Property	(O)	(4,138,283)	(1,570,933)	(345,426)	(6,054,642)	
29	Total Revenue Requirements (Line 14 thru 28)		65,199,437	16,277,309	11,395,264	92,872,010	

Worksheet 1B

Northeast Utilities System Companies'
Adjusted Annual Revenue Requirements of PTF Facilities for costs in 2009
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
for Rates billed June 1, 2010 - May 31, 2011
Post - 1996

Line No.		Attachment F Reference *Section:*	CL&P	PSNH	WMECO	Total	Reference
	I. INVESTMENT BASE						
1	Transmission Plant	(A)(1)(a)	1,824,954,421	283,386,061	90,343,016	2,198,683,498	w/s 3A line 1
2	General Plant	(A)(1)(b)	37,212,290	21,636,393	3,309,273	62,157,956	w/s 3A line 2
3	Plant Held For Future Use	(A)(1)(c)	1,723,245	3,528,234	7,214,155	12,465,634	w/s 3A line 4
4	Total Plant (Lines 1+2+3)		1,863,889,956	308,550,688	100,866,444	2,273,307,088	
5	Accumulated Depreciation	(A)(1)(d)	267,281,640	64,944,070	27,530,720	359,756,430	w/s 3A line 7
6	Accumulated Deferred Income Taxes	(A)(1)(e)	115,680,829	38,926,884	13,284,172	167,891,885	w/s 3A line 10
7	Loss On Reacquired Debt	(A)(1)(f)	3,998,565	1,364,749	48,171	5,411,485	w/s 3A line 11
8	Other Regulatory Assets	(A)(1)(g)	14,173,685	1,847,613	83,734	16,105,032	w/s 3A line 15
9	Net Investment (Line 4-5-6+7+8)		1,499,099,737	207,892,096	60,183,457	1,767,175,290	
10	Prepayments	(A)(1)(h)	4,004,347	5,178,310	2,375,048	11,557,705	w/s 3A line 16
11	Materials & Supplies	(A)(1)(i)	11,976,742	2,271,282	2,793,367	17,041,391	w/s 3A line 17
12	Cash Working Capital	(A)(1)(j)	6,913,125	1,702,771	561,995	9,177,891	w/s 3A line 24
13	Total Investment Base (Line 9+10+11+12)		1,521,993,951	217,044,459	65,913,867	1,804,952,277	
II.	REVENUE REQUIREMENTS						
14	Investment Return and Income Taxes	(A)	197,321,798	25,324,292	8,238,238	230,884,328	w/s 2A
15	Depreciation Expense	(B)	42,604,756	6,181,623	1,576,566	50,362,945	w/s 4A line 3
16	Amortization of Loss on Reacquired Debt	(C)	320,605	120,406	4,431	445,442	w/s 4A line 4
17	Investment Tax Credit	(D)	(512,168)	(9,141)	(27,348)	(548,657)	w/s 4A line 5
18	Property Tax Expense	(E)	18,644,032	5,007,744	1,381,592	25,033,368	w/s 4A line 8
19	Payroll Tax Expense	(F)	384,092	97,982	38,914	520,988	w/s 4A line 19
20	Operation & Maintenance Expense	(G)	24,597,041	7,971,563	2,292,122	34,860,726	w/s 4A line 17
21	Administrative & General Expense	(H)	30,707,956	5,650,606	2,203,841	38,562,403	w/s 4A line 18
22	Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	
23	Transmission Related Expense from Generators	(L)		-	-	-	
24	Transmission Related Taxes and Fees Charge	(M)	11,334,646	(41,913)	(40,061)	11,252,672	Attachment B line 16
25	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(992,103)	(154,346)	(53,120)	(1,199,569)	Attachment C line 12
26	Total Revenue Requirements (Line 14 thru 25)		324,410,655	50,148,816	15,615,175	390,174,646	

Northeast Utilities System Companies'

Adjusted Annual Revenue Requirements of post-2003 PTF Incremental Return for costs in 2009
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
for Rates billed June 1, 2010 - May 31, 2011

Line		CL&P	PSNH	WMECO	Total	Reference
	I. INVESTMENT BASE					
1	Transmission Plant	$ 1,565,904,988	$ 126,576,637	$ 12,308,623	$ 1,704,790,248	Attachment A1
2	Accumulated Depreciation	$ 65,413,574	$ 7,294,255	$ 1,066,502	$ 73,774,331	↓
3	Accumulated Deferred Income Taxes	$ 57,056,085	$ 8,958,048	$ 1,371,696	$ 67,385,829	
4	Net Investment (Line 1-2-3)	$ 1,443,435,329	$ 110,324,334	$ 9,870,425	$ 1,563,630,088	
	II. INCREMENTAL RETURN					
5	Incremental Revenue Requirements	$ 11,859,698	$ 871,838	$ 81,205	$ 12,812,741	w/s 2A

Northeast Utilities System Companies'

Adjusted Annual Revenue Requirements of Incremental Return For M-N Advance Technology

To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects

for Rates billed June 1, 2010 - May 31, 2011

Line			CL&P		Reference
	I.	INVESTMENT BASE			
1		Transmission Plant	$	407,058,284	Attachment A2
2		Accumulated Depreciation	$	8,407,213	↓
3		Accumulated Deferred Income Taxes	$	8,418,797	
4		Net Investment (Line 1-2-3)	$	390,232,274	
	II.	INCREMENTAL RETURN			
5		Incremental Revenue Requirements	$	1,505,009	w/s 2A

Northeast Utilities System Companies'
Adjusted Transmission Revenue Requirements of PTF Facilities
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
2009 True-up
Pre-97 and Post-1996

	I. ANNUAL TRUE-UP	**PRE-97**	**POST-96**	**TOTAL**	**Reference**
1	True-up 2009 Actual Annual RR @ 11.64% ROE	93,509,034	412,844,962	506,353,996	2009 ATTR
2	Adjusted 2009 True-up for MN/GB 12-C decsion	92,872,010	404,492,396	497,364,406	w/s 1A, 1B, 1C, 1D
3	Total Rate Year Surcharge/(Refund) (Line 2 - 1)	(637,024)	(8,352,566)	(8,989,590)	

Northeast Utilities System Companies'
FERC Interest Calculation associated with Surcharge / (Refund)
Adjusted Transmission Revenue Requirements of PTF Facilities
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
PRE-97 / Post 96

	Surcharge / (Refund)
Pre	$ (637,024)
Post	$ (8,352,566)

Initial Billing Period	Balance Pre 97	Balance Post 96	FERC Monthly Interest Rate	Interest Pre 97	Interest Post 96
June 2009	$ (637,024)	$ (8,352,566)	0.28%	$ (1,784)	$ (23,387)
July 2009	$ (638,808)	$ (8,375,953)	0.28%	$ (1,789)	$ (23,453)
August 2009	$ (638,808)	$ (8,375,953)	0.28%	$ (1,789)	$ (23,453)
September 2009	$ (638,808)	$ (8,375,953)	0.27%	$ (1,725)	$ (22,615)
October 2009	$ (644,111)	$ (8,445,474)	0.28%	$ (1,804)	$ (23,647)
November 2009	$ (644,111)	$ (8,445,474)	0.27%	$ (1,739)	$ (22,803)
December 2009	$ (644,111)	$ (8,445,474)	0.28%	$ (1,804)	$ (23,647)
January 2010	$ (649,458)	$ (8,515,571)	0.28%	$ (1,818)	$ (23,844)
February 2010	$ (649,458)	$ (8,515,571)	0.25%	$ (1,624)	$ (21,289)
March 2010	$ (649,458)	$ (8,515,571)	0.28%	$ (1,818)	$ (23,844)

Worksheet 1E

Initial Billing Period	Balance		FERC Monthly Interest Rate	Interest	
	Pre 97	Post 96		Pre 97	Post 96
April 2010	$ (654,718)	$ (8,584,548)	0.27%	$ (1,768)	$ (23,178)
May 2010	$ (654,718)	$ (8,584,548)	0.28%	$ (1,833)	$ (24,037)
June 2010	$ (654,718)	$ (8,584,548)	0.27%	$ (1,768)	$ (23,178)
July 2010	$ (660,087)	$ (8,654,941)	0.28%	$ (1,848)	$ (24,234)
August 2010	$ (660,087)	$ (8,654,941)	0.28%	$ (1,848)	$ (24,234)
September 2010	$ (660,087)	$ (8,654,941)	0.27%	$ (1,782)	$ (23,368)
October 2010	$ (665,565)	$ (8,726,777)	0.28%	$ (1,864)	$ (24,435)
November 2010	$ (665,565)	$ (8,726,777)	0.27%	$ (1,797)	$ (23,562)
December 2010	$ (665,565)	$ (8,726,777)	0.28%	$ (1,864)	$ (24,435)
January 2011	$ (671,090)	$ (8,799,209)	0.28%	$ (1,879)	$ (24,638)
February 2011	$ (671,090)	$ (8,799,209)	0.25%	$ (1,678)	$ (21,998)
March 2011	$ (671,090)	$ (8,799,209)	0.28%	$ (1,879)	$ (24,638)
April 2011	$ (676,526)	$ (8,870,483)	0.27%	$ (1,827)	$ (23,950)
May 2011	$ (676,526)	$ (8,870,483)	0.28%	$ (1,894)	$ (24,837)
	Total Surcharge/(Refund)			**$ (680,247)**	**$ (8,919,270)**

	Interest	Principal	Total (check)	variance
Pre 97	$ (43,223)	$ (637,024)	$ (680,247)	$ -
Post 96	$ (566,704)	$ (8,352,566)	$ (8,919,270)	$ -
	$ (609,927)	$ (8,989,590)	$ (9,599,517)	

Note: Minor immaterial variance due to rounding

Worksheet 2A

Connecticut Light & Power Company (CL&P)
Adjusted Investment Return and Income Taxes for costs in 2009
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Pre 97
for Rates billed June 1, 2010 - May 31, 2011

	CAPITALIZATION 12/31/2009	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 2,317,095,041	48.21%	6.30%	3.04%	
PREFERRED STOCK	$ 116,614,879	2.43%	4.81%	0.12%	0.12%
COMMON EQUITY	$ 2,372,767,572	49.36%	11.64%	5.75%	5.75%
TOTAL INVESTMENT RETURN	$ 4,806,477,492	100.00%		8.91%	5.87%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.08910

(b) Federal Income Tax

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

$$= \frac{0.0587\ +(\ (108{,}845) + 500{,}230\ )\ /\ 323{,}501{,}518\ )\ \text{x}\ 0.35\ )}{(\ 1 - 0.35\ )}$$

= 0.0322591

(c) State Income Tax

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

$$= \frac{0.0587\ +(\ (108{,}845) + 500{,}230\ )\ /\ 323{,}501{,}518\ ) + 0.0322591\ )*\ 0.0825}{(\ 1 - 0.0825\ )}$$

= 0.0082877

(a)+(b)+(c) Cost of Capital Rate = 0.1296468

	Pre-1997 PTF	
INVESTMENT BASE	$ 323,501,518	From Worksheet 1, line 13
x Cost of Capital Rate	0.1296468	
= Investment Return and Income Taxes	$ 41,940,937	To Worksheet 1, line 14

Connecticut Light & Power Company (CL&P)
Adjusted Investment Return and Income Taxes for costs in 2009
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
POST-96
for Rates billed June 1, 2010 - May 31, 2011

	CAPITALIZATION 12/31/2009	CAPITALIZATION RATIOS	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 2,317,095,041	48.21%	6.30%	3.04%	
PREFERRED STOCK	$ 116,614,879	2.43%	4.81%	0.12%	0.12%
COMMON EQUITY	$ 2,372,767,572	49.36%	11.64%	5.75%	5.75%
TOTAL INVESTMENT RETURN	$ 4,806,477,492	100.00%		8.91%	5.87%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.08910

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

= 0.0587 +((512,168) + 2,353,812) / 1,521,993,951) x 0.35)
(1 - 0.35)

= 0.0322592

(c) State Income Tax = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)*State Income Tax Rate
(1 - State Income tax Rate)

= 0.0587 +((512,168) + 2,353,812) / 1,521,993,951) + 0.0322592)* 0.0825
(1 - 0.0825)

= 0.0082877

(a)+(b)+(c) Cost of Capital Rate = 0.1296469

	Post - 1996 PTF	
INVESTMENT BASE	$ 1,521,993,951	From Worksheet 1, line 13
x Cost of Capital Rate	0.1296469	
= Investment Return and Income Taxes	$ 197,321,798	To Worksheet 1, line 14

Connecticut Light & Power Company (CL&P)
Adjusted Investment Return and Income Taxes for costs in 2009
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Post 2003
Incremental ROE Adder For RSP Projects

	CAPITALIZATION 12/31/2009	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 2,317,095,041	48.21%	#N/A		
PREFERRED STOCK	116,614,879	2.43%			
COMMON EQUITY	2,372,767,572	49.36%	1.00%	0.49%	0.49%
TOTAL INVESTMENT RETURN	$ 4,806,477,492	100.00%		0.49%	0.49%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0049

(b) Federal Income Tax

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

$$= \frac{0.0049 + ((0 + 0) / 1,443,435,329) \times 0.35)}{(1 - 0.35)}$$

= 0.0026385

(c) State Income Tax

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

$$= \frac{0.0049 + ((0 + 0) / 1,443,435,329) + 0.0026385)^{*} 0.0825}{(1 - 0.0825)}$$

= 0.0006778

(a)+(b)+(c) Cost of Capital Rate = 0.0082163

	(post-2003 PTF)	
INVESTMENT BASE	$ 1,443,435,329	From Worksheet 1 Line 4
x Cost of Capital Rate	0.0082163	
= Investment Return and Income Taxes	11,859,698	To Worksheet 1a Line 5

Connecticut Light & Power Company (CL&P)
Adjusted Investment Return and Income Taxes for costs in 2009
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Incremental ROE For M-N Advance Technology

	CAPITALIZATION 12/31/2009	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 2,317,095,041	48.21%	#N/A		
PREFERRED STOCK	$ 116,614,879	2.43%			
COMMON EQUITY	$ 2,372,767,572	49.36%	0.46%	0.23%	0.23%
TOTAL INVESTMENT RETURN	$ 4,806,477,492	100.00%		0.23%	0.23%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0023

(b) Federal Income Tax

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

$$= \frac{0.0023 \quad + ((\quad 0 \quad + \quad 0 \quad) \;/\; 390{,}232{,}274 \quad) \quad \times \quad 0.35\;)}{(\quad 1 \quad - \quad 0.35 \quad)}$$

$$= 0.0012385$$

(c) State Income Tax

$$= \frac{\text{R.O.E.} + \;((\;\text{PTF Inv. Tax Credit} + \text{Eq. AFUDC of Deprec. Exp.}\;)\;/\;\text{PTF Inv. Base}) \quad + \quad \text{Federal Income Tax}\;)^{*} \;\text{State Income Tax Rate}}{(\;1 - \text{State Income Tax Rate}\;)}$$

$$= \frac{0.0023 \quad + ((\quad 0 \quad + \quad 0\;) \;/\; 390{,}232{,}274 \quad) \quad + \quad 0.0012385 \quad)^{*} \quad 0.0825}{(\quad 1 \quad - \quad 0.0825\;)}$$

$$= 0.0003182$$

(a)+(b)+(c) Cost of Capital Rate = 0.0038567

	(M-N Adv Tech)	
INVESTMENT BASE	$ 390,232,274	From Worksheet 1 Line 4
x Cost of Capital Rate	0.0038567	
= Investment Return and Income Taxes	$ 1,505,009	To Worksheet 1a Line 5

Worksheet 3A

Connecticut Light & Power Company (CL&P)
Adjusted Rate Base Items
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Calendar Year 2009

					PRE-97 PTF		POST-96 PTF		
Line No.		(1) Total	(2) Wage/Plant Allocation Factors (a)	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	(6) PTF Allocation Factor (b)	(7) = (3)*(6) PTF Allocated	Reference
	Transmission Plant								
1	Transmission Plant					387,837,863		1,824,954,421	Attachment A
2	General Plant	50,434,092		50,434,092	15.6805%	7,908,318	73.7840%	37,212,290	FF1 page 206-207 ln. 96, footnote
3	Total (line 1+2)	50,434,092		50,434,092		395,746,181		1,862,166,711	
4	Transmission Plant Held for Future Use	2,335,527	(c)	2,335,527	15.6805%	366,222	73.7840%	1,723,245	(c)
	Transmission Accumulated Depreciation								
5	Transmission Accum. Depreciation	354,960,836		354,960,836	15.6805%	55,659,634	73.7840%	261,904,303	FF1 page 219 ln. 25
6	General Plant Accum.Depreciation	7,287,945		7,287,945	15.6805%	1,142,786	73.7840%	5,377,337	FF1 page 219 ln. 28, footnote
7	Total (line 5+6)	362,248,781		362,248,781		56,802,420		267,281,640	
	Transmission Accumulated Deferred Taxes								
8	Accumulated Deferred Taxes (281 to 283)	(196,341,441)		(196,341,441)	15.6805%	(30,787,320)	73.7840%	(144,868,569)	FF1 page 274 ln. 9 & 276 ln. 19 footnote
9	Accumulated Deferred Taxes (190)	39,558,359	(d)	39,558,359	15.6805%	6,202,948	73.7840%	29,187,740	(d)
10	Total (line 8+9)	(156,783,082)		(156,783,082)		(24,584,372)		(115,680,829)	
11	Transmission loss on Reacquired Debt	5,419,285		5,419,285	15.6805%	849,771	73.7840%	3,998,565	FF1 page 110 ln. 81, footnote
	Other Regulatory Assets								
12	FAS 106	-		-	15.6805%	-	73.7840%	-	FF1 page 232
13	FAS 109	22,332,713		22,332,713	15.6805%	3,501,881	73.7840%	16,477,969	FF1 page 232 ln. 10, footnote
14	Other Regulatory Liabilities (254.DK)	(3,123,013)		(3,123,013)	15.6805%	(489,704)	73.7840%	(2,304,284)	FF1 page 278 ln. 5, footnote
15	Total (line 12+13+14)	19,209,700		19,209,700		3,012,177		14,173,685	
16	Transmission Prepayments (165)	5,427,121		5,427,121	15.6805%	851,000	73.7840%	4,004,347	FF1 page 110 ln. 57, footnote
17	Transmission Materials and Supplies	16,232,167		16,232,167	15.6805%	2,545,285	73.7840%	11,976,742	FF1 page 227 ln. 8
18	Cash Working Capital								
19	Operation & Maintenance Expense					5,227,338		24,597,041	w/s 4A, Line 17
20	Administrative & General Expense					6,526,023		30,707,956	w/s 4A, Line 18
21	Transmission Support Expense					388,032		-	w/s 7
22	Subtotal (line 19+20+21)					12,141,393		55,304,997	
23						0.125		0.125	x 45 / 360
24	Total (line 22 * line 23)					1,517,674		6,913,125	

(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	33,731,829	FF1 page 214 ln. 11
	Less Third Underground Conduit Duct	31,396,302	
		2,335,527	

(d)	Account 190	66,092,537	FF1 page 234 ln. 18, footnote
	Less Reserve for Disputed Transactions	26,534,178	
	Total Account 190	39,558,359	

Connecticut Light & Power Company (CL&P)
Adjusted Expense Items
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Calendar Year 2009

Worksheet 4A

					PRE-97 PTF		POST-96 PTF		
Line No.		(1) Total	(2) Wage/Plant Allocation Factors (a)	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) Pre-97 PTF Allocated	(6) PTF Allocation Factor (b)	(7) = (3)*(6) Post-96 PTF Allocated	Reference
	Depreciation Expense								
1	Transmission Depreciation	56,047,436		56,047,436	15.6805%	8,788,518	73.7840%	41,354,040	FF 1 page 336 ln. 7
2	General Depreciation	1,695,104		1,695,104	15.6805%	265,801	73.7840%	1,250,716	FF1 page 336 ln. 10, footnote
3	Total (line 1+2)	57,742,540		57,742,540		9,054,319		42,604,756	
4	Amortization of Loss on Reacquired Debt	434,518		434,518	15.6805%	68,135	73.7840%	320,605	FF1 page 114, ln. 64, footnote
5	Amortization of Investment Tax Credits	694,145		694,145	15.6805%	108,845	73.7840%	512,168	FF1 page 266 ln. 8, footnote - difference of PY-CY
	Property Taxes								
6	Transmission Property Taxes	25,268,394		25,268,394	15.6805%	3,962,211	73.7840%	18,644,032	FF1 page 262 ln. 25, footnote
7	General Property Taxes (c)	-		-	15.6805%	-	73.7840%	-	
8	Total (line 6+7)	25,268,394		25,268,394		3,962,211		18,644,032	
	Transmission Operation and Maintenance								
9	Operation and Maintenance	142,969,527		142,969,527	15.6805%	22,418,337	73.7840%	105,488,636	FF1 page 321 ln. 112
10	Transmission of Electricity by Others - #565	95,602,919		95,602,919	15.6805%	14,991,016	73.7840%	70,539,658	FF1 page 321 ln. 96
11	Load Dispatching - #561	-		-	15.6805%	-	73.7840%	-	FF1 page 321 ln. 84
12	Account 561.1	2,919,523		2,919,523	15.6805%	457,796	73.7840%	2,154,141	FF1 page 321 ln. 85
13	Account 561.2	4,969,493		4,969,493	15.6805%	779,241	73.7840%	3,666,691	FF1 page 321 ln. 86
14	Account 561.3	1,684,310		1,684,310	15.6805%	264,108	73.7840%	1,242,751	FF1 page 321 ln. 87
15	Account 561.4	4,456,731		4,456,731	15.6805%	698,838	73.7840%	3,288,354	FF1 page 321 ln. 88
16	**Station Expenses & Rents - #562 / #567	-		-	15.6805%	-	73.7840%	-	
17	O&M less lines 10 thru 16	33,336,551		33,336,551		5,227,338		24,597,041	
	Transmission Administrative and General								
18	Administrative and General	41,618,719		41,618,719	15.6805%	6,526,023	73.7840%	30,707,956	FF1 page 320 ln. 197, footnote
19	*Payroll Tax Expense*	*520,563*		520,563	15.6805%	81,627	73.7840%	384,092	
	Federal Unemployment	4,626							FF1 page 262 ln. 19i, footnotes
	FICA	379,729							FF1 page 262 ln. 5i, footnote
	Medicare	110,444							FF1 page 262 ln. 9i, footnote
	CT Unemployment	24,301							FF1 page 262 ln. 15i, footnote
	DC Unemployment	19							FF1 page 262.1 ln. 13i, footnote
	FL Unemployment	-							FF1 page 262 & 263 footnote
	GA Unemployment	-							FF1 page 262 & 263 footnote
	MA Unemployment	56							FF1 page 262 ln. 32i, footnote
	MA Universal Health	40							FF1 page 262 ln. 33i, footnote
	NH Unemployment	1,303							FF1 page 262.1 ln. 3i, footnote
	NJ Unemployment	-							FF1 page 262 & 263 footnote
	NY Unemployment	45							FF1 page 262.1 ln. 9i, footnote
	Total	520,563	To Line 19						

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

(a) All expenses functionalized per FERC Form 1; therefore, no need to use Wage/Plant Allocation Factor (column 2)

(b) ws 5A & 5B

(c) Transmission related general property taxes are included in the Transmission Property tax number footnoted in the FF1.

Worksheet 5A

Northeast Utilities System Companies
Adjusted Allocation Factors
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Calendar Year 2009
PRE-1997

Line No.		CL&P	PSNH	WMECO	TOTAL	Reference
	PTF Transmission Plant Allocation Factor					
1	PTF Transmission Investment	387,837,863	96,744,902	65,630,687	550,213,452	w/s 3A line 1
2	Total Transmission Investment	2,473,375,066	404,748,885	173,156,024	3,051,279,975	FF1 page 206-207 ln 58
3	Percent Allocation (Line 1/ Line 2)	15.6805%	23.9025%	37.9026%	18.0322%	
	Transmission Wages and Salaries Allocation Factor					
4	Direct Transmission Wages and Salaries	5,098,153	1,026,302	521,101	6,645,556	FF1 page 354 ln 21
5	Affiliated Company Transmission Wages and Salaries	12,810,483	1,200,901	474,863	14,486,247	w/s 6 line 15
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	17,908,636	2,227,203	995,964	21,131,803	
7	Total Wages and Salaries	97,637,292	71,434,119	17,644,084	186,715,495	FF1 page 354 ln 28
8	Administrative and General Wages and Salaries	19,170,120	15,405,167	2,828,496	37,403,783	FF1 page 354 ln 27
9	Affiliated Company Wages and Salaries less A&G	78,530,934	18,290,009	11,713,052	108,533,995	w/s 6 line 30
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	156,998,106	74,318,961	26,528,640	257,845,707	
11	Percent Allocation (Line 6 / Line 10)	11.4069%	2.9968%	3.7543%	8.1955%	
	Plant Allocation Factor					
12	Total Transmission Investment (Line 2)	2,473,375,066	404,748,885	173,156,024	3,051,279,975	
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	50,434,092	30,902,379	6,342,726	87,679,197	w/s 3A line 2
14	*= Revised Numerator (Line 12 + Line 13)*	2,523,809,158	435,651,264	179,498,750	3,138,959,172	
15	Total Plant in Service	6,479,643,837	2,405,275,413	834,303,616	9,719,222,866	FF1 206-207 ln 100
16	Percent Allocation (Line 14 / Line 15)	38.9498%	18.1123%	21.5148%	32.2964%	

Worksheet 5B

Northeast Utilities System Companies
Adjusted Allocation Factors
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Calendar Year 2009
POST - 1996

Line No.		CL&P	PSNH	WMECO	TOTAL	Reference
	PTF Transmission Plant Allocation Factor					
1	PTF Transmission Investment	1,824,954,421	283,386,061	90,343,016	2,198,683,498	w/s 3A line 1
2	Total Transmission Investment	2,473,375,066	404,748,885	173,156,024	3,051,279,975	FF1 page 206-207 ln 58
3	Percent Allocation (Line 1/ Line 2)	73.7840%	70.0153%	52.1743%	72.0577%	
	Transmission Wages and Salaries Allocation Factor					
4	Direct Transmission Wages and Salaries	5,098,153	1,026,302	521,101	6,645,556	FF1 page 354 ln 21
5	Affiliated Company Transmission Wages and Salaries	12,810,483	1,200,901	474,863	14,486,247	w/s 6 line 15
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	17,908,636	2,227,203	995,964	21,131,803	
7	Total Wages and Salaries	97,637,292	71,434,119	17,644,084	186,715,495	FF1 page 354 ln 28
8	Administrative and General Wages and Salaries	19,170,120	15,405,167	2,828,496	37,403,783	FF1 page 354 ln 27
9	Affiliated Company Wages and Salaries less A&G	78,530,934	18,290,009	11,713,052	108,533,995	w/s 6 line 30
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	156,998,106	74,318,961	26,528,640	257,845,707	
11	Percent Allocation (Line 6 / Line 10)	11.4069%	2.9968%	3.7543%	8.1955%	
	Plant Allocation Factor					
12	Total Transmission Investment (Line 2)	2,473,375,066	404,748,885	173,156,024	3,051,279,975	
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	50,434,092	30,902,379	6,342,726	87,679,197	w/s 3A line 2
14	*= Revised Numerator (Line 12 + Line 13)*	2,523,809,158	435,651,264	179,498,750	3,138,959,172	
15	Total Plant in Service	6,479,643,837	2,405,275,413	834,303,616	9,719,222,866	FF1 206-207 ln 100
16	Percent Allocation (Line 14 / Line 15)	38.9498%	18.1123%	21.5148%	32.2964%	

Attachment A

Connecticut Light and Power Company
Substations and Lines
PTF Investment as of 12/31/09 (101 + 106)
Revised 4-25-11 For M-N & G-B Projects FINAL 12C

	350	352	353	354	355	356	357	358	359	361	362	Grand Total
1997	39,442.79	38,745.58	4,938,497.20	112,607.52	118,897.46	4,837,106.76	0.00	0.00	0.00	15,508.21	78,466.29	10,179,271.81
1998	(6,147.32)	53,794.35	393,855.60	0.00	113,374.45	105,664.19	0.00	0.00	0.00	16,313.27	23,064.44	699,918.97
1999	0.00	0.00	584,378.74	28,802.26	26,718.64	6,688.86	0.00	0.00	0.00	10,683.89	32,726.56	689,998.95
2000	0.00	0.00	2,620,178.77	0.00	260,740.55	5,663.06	136,633.03	179,004.16	61,360.97	37,629.81	216,448.67	3,517,659.02
2001	379,320.03	249,013.72	17,387,528.16	0.00	1,274,515.96	28,447.99	0.00	0.00	0.00	0.00	23,240.49	19,342,066.35
2002	0.00	104,235.12	5,985,449.21	184,907.20	1,932,736.37	2,939,424.59	0.00	0.00	0.00	150,659.49	156,444.08	11,453,856.06
2003	(30,877.09)	192,264.15	13,929,399.84	55,332.28	8,981,550.27	2,570,587.65	0.00	0.00	0.00	43,329.91	93,528.19	25,835,115.20
2004	607,255.01	1,996,199.78	56,089,313.65	0.00	2,261,294.57	377,603.79	1,058,908.61	1,180,509.94	18,824.61	7,627.89	340,694.08	63,938,231.93
2005	2,790,727.81	4,562,774.63	77,071,190.67	0.00	3,492,551.70	3,110,943.64	16,291,589.29	9,150,257.10	0.00	163,514.63	127,888.34	116,761,437.81
2006	11,343,316.97	7,283,645.70	79,167,112.08	0.00	20,113,526.25	9,020,162.39	20,432,422.46	67,443,769.08	3,968,765.88	1,012,919.11	896,701.29	220,682,341.23
2007	10,957,350.78	3,591,028.84	78,158,261.68	0.00	81,443,289.80	46,909,919.14	0.00	0.00	29,274.47	19,465.06	141,854.77	221,250,444.54
2008	1,318,453.62	8,425,563.42	210,910,674.43	384,927.18	101,312,805.76	60,198,623.55	348,295,952.99	298,834,688.16	18,153,687.59	217,774.79	254,929.76	1,048,308,081.23
2009	1,966,648.43	8,633,887.76	54,306,016.38	0.00	8,998,022.31	3,637,791.67	0.00	0.00	466,321.60	2,147,697.63	2,139,611.63	82,295,997.42
Post-1996	29,365,491.03	35,131,153.05	601,541,856.41	766,576.44	230,330,024.09	133,748,627.28	386,215,506.38	376,788,228.44	22,698,235.12	3,843,123.68	4,525,598.59	1,824,954,420.51

Attachment A1

CL&P RSP INVESTMENT BY PLANT ACCOUNT AT 12-31-09

REVISED 4-25-11 for M-N & G-B Projects FINAL 12C

		Data		
Plant A/C	Work Order Inservice Year	Sum of Gross Plant2	Sum of Accum Depr2	Sum of Net Plant2
350	2004	423,777.17	30,740.30	393,036.87
	2005	2,350,091.18	143,150.80	2,206,940.38
	2006	11,244,274.29	293,451.33	10,950,822.96
	2007	10,947,554.21	387,051.60	10,560,502.61
	2008	1,056,572.53	20,441.40	1,036,131.13
	2009	1,962,326.02	11,581.18	1,950,744.84
350 Total		27,984,595.40	886,416.61	27,098,178.79
352	2004	1,166,407.66	157,276.35	1,009,131.31
	2005	4,436,408.88	499,757.69	3,936,651.19
	2006	7,263,259.66	650,287.18	6,612,972.48
	2007	3,456,097.67	226,039.47	3,230,058.20
	2008	8,283,182.15	332,656.41	7,950,525.74
352 Total		24,605,356.02	1,866,017.10	22,739,338.92
353	2004	51,357,088.56	5,157,628.05	46,199,460.51
	2005	66,604,019.72	5,640,437.34	60,963,582.39
	2006	68,218,345.79	4,637,550.68	63,580,795.11
	2007	54,953,072.14	2,758,004.58	52,195,067.56
	2008	187,133,290.17	5,830,682.18	181,302,607.99
	2009	370,039.18	3,984.85	366,054.33
353 Total		428,635,855.56	24,028,287.68	404,607,567.89
354	2008	84,581.78	3,381.00	81,200.78
354 Total		84,581.78	3,381.00	81,200.78
355	2004	233,478.02	47,088.25	186,389.77
	2005	2,569,188.47	419,376.46	2,149,812.01
	2006	17,448,331.55	2,196,180.30	15,252,151.25
	2007	75,986,465.21	6,799,914.05	69,186,551.16
	2008	98,835,205.35	5,317,964.62	93,517,240.73
355 Total		195,072,668.60	14,780,523.67	180,292,144.93
356	2004	163,768.35	26,124.35	137,644.00
	2005	2,669,039.42	349,145.99	2,319,893.43
	2006	5,483,973.68	559,124.40	4,924,849.28
	2007	36,339,794.51	2,652,017.52	33,687,776.99
	2008	60,375,535.37	2,648,467.66	57,727,067.71
356 Total		105,032,111.34	6,234,879.93	98,797,231.41
357	2004	1,058,908.61	55,412.11	1,003,496.50
	2005	16,291,589.29	776,416.57	15,515,172.71
	2006	20,432,422.46	854,502.50	19,577,919.96
	2007	0.00	0.00	0.00
	2008	348,295,952.99	8,414,746.68	339,881,206.32
357 Total		386,078,873.35	10,101,077.86	375,977,795.49
358	2004	1,180,509.94	21,553.49	1,158,956.45
	2005	9,150,257.10	162,273.22	8,987,983.88
	2006	67,217,115.44	1,141,055.57	66,076,059.88
	2007	0.00	0.00	0.00
	2008	298,834,688.16	5,574,874.42	293,259,813.74
358 Total		376,382,570.64	6,899,756.70	369,482,813.94
359	2006	3,919,366.48	202,669.92	3,716,696.56
	2008	18,109,009.00	410,563.30	17,698,445.70
359 Total		22,028,375.48	613,233.22	21,415,142.26
Grand Total		1,565,904,988.18	65,413,573.76	1,500,491,414.42

Attachment A2

CL+P ADVANCED TECHNOLOGY INVESTMENT AT 12-31-09

REVISED 4-25-11 FOR M-N PROJECT FINAL 12C

Work Order Description	Plant A/C	Work Order In Service	Gross Plant	Accum Depr	Net Plant
MN 345KV SEG1 BESECK SWITCH STATION	35389	2007	214,782.79	10,779.60	204,003.19
MN 345KV SEGMENT 2 EAST DEVON S/S-115KV WORK	35389	2008	242,836.18	7,566.27	235,269.91
MN 345KV SEGMENT 2 EAST DEVON S/S-345KV WORK	35389	2008	155,527.35	4,845.91	150,681.44
MN 345KV SEGMENT 2 EAST DEVON S/S-AUTOS	35389	2008	131,699.72	4,103.49	127,596.23
MN 345KV SEGMENT 2 EAST DEVON S/S-AUTOS	35389	2008	167,348.48	5,214.23	162,134.26
MN 345KV SEGMENT 3 EAST DEVON TO SINGER	357	2008	29,715,452.96	717,918.20	28,997,534.76
MN 345KV SEGMENT 3 EAST DEVON TO SINGER	358	2008	20,920,696.08	283,108.69	20,637,587.39
MN 345KV SEG 3 ROW EASEMENTS	35002	2007	154,082.53	5,506.98	148,575.55
MN 345KV SEG 3 ROW EASEMENTS	35002	2007	318,714.78	11,391.00	307,323.78
BRIDGEPORT 2006 AQUIRED EASEMENTSSEG 3 MN345K	35002	2006	551,702.94	26,849.66	524,853.28
MN 345KV SEG 3 ROW EASEMENT LL 430_BRIDGEPORT	35002	2009	170,502.97	1,291.87	169,211.10
MN 345KV SEG 3 ROW EASEMENT LL 430.01 BRIDGEP	35002	2009	53,105.96	402.37	52,703.59
MN 345KV SEG 3 ROW EASEMENT LL 442 & 443	35002	2009	54,542.04	413.25	54,128.79
MN 345KV SEG 3 ROW EASEMENT LL 451.02 B'PORT	35002	2009	14,681.15	111.24	14,569.91
MN 345KV SEGMENT 4 SINGER TO NORWALK	357	2008	204,484,315.16	4,940,292.00	199,544,023.16
MN 345KV SEGMENT 4 SINGER TO NORWALK	358	2008	133,472,056.29	1,806,206.56	131,665,849.73
MN 345KV SEGMENT 4 NORWALK SS	35389	2008	85,384.03	2,660.38	82,723.65
MN 345KV SEGMENT 4 NORWALK SS	35389	2008	268,338.28	8,360.86	259,977.42
MN 345KV SEGMENT 4 NORWALK SS	35389	2008	128,080.84	3,990.73	124,090.10
MN 345KV SEGMENT 4 NORWALK SS_SHUNT REACTORS	35389	2008	7,967,373.18	248,246.69	7,719,126.49
MN 345KV SEG 4 ROW EASEMENTS	35002	2007	832,242.54	29,744.74	802,497.80
MN 345KV SEG 4 ROW EASEMENTS	35002	2007	1,969,149.47	70,378.34	1,898,771.13
MN 345KV SEG 4 ROW EASEMENTS	35002	2007	1,100,725.15	39,340.42	1,061,384.73
FAIRFIELD 2006 AQUIRED EASEMENTS MN345KV SEG4	35002	2006	1,276,433.81	62,120.05	1,214,313.76
WESTPORT 2006 EASEMENTS AQUIRED MN345KV SEG4	35002	2006	1,471,790.40	71,627.45	1,400,162.95
NORWALK 2006 EASEMENTS AQUIRED MN345KV SEG 4	35002	2006	871,657.40	42,420.85	829,236.55
MN 345KV SEG 4 ROW EASEMENT LL 421 FAIRFIELD	35002	2009	172,772.58	1,309.06	171,463.52
MN 345KV SEG 4 ROW EASEMENT LL 520 WESTPORT	35002	2009	70,682.00	535.54	70,146.46
MN 345KV SEG 4 ROW EASEMENT LL 543.01 WESTPOR	35002	2008	21,606.96	476.82	21,130.14
			407,058,284.02	8,407,213.25	398,651,070.76

Adjusted Transmission Related Taxes and Fees
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Calendar Year 2009

		CL&P	PSNH	WMECO	TOTAL	Reference
1	CT Gross Earnings Tax	16,213,642	-	-	16,213,642	FF1 p 262 FN
2	CT Insurance Premium Excise Tax	53,768	4,949	1,604	60,321	↓
3	NH Excise Tax	-	14,066	-	14,066	
4	Fed. Excise Tax	-	-	-	-	
5	Mass. Excise Tax	23	4	1	28	
6	Corporation Business Tax	-	-	771	771	
7	MA Sales Tax	-	-	1,917	1,917	
8	CT Sales Tax	(909,068)	(178,815)	(81,774)	(1,169,657)	
9	NH Business Enterprise Tax	3,565	99,934	698	104,197	
10	NY Business Franchise Tax	-	-	-	-	
11	Federal Highway use Tax	-	-	-	-	
12	TOTAL (sum of lines 1 to 11)	15,361,930	(59,862)	(76,783)	15,225,285	To Total RR Wksht 1
13	Pre-97 %	15.6805%	23.9025%	37.9026%		w/s 5A
14	Total Pre-97 Related Exp. (line 12 x13)	2,408,827	(14,309)	(29,103)	2,365,416	To w/s 1A
15	Post-96 %	73.7840%	70.0153%	52.1743%		w/s 5B
16	Total Post-96 Related Exp. (line 12 x 15)	11,334,646	(41,913)	(40,061)	11,252,672	To w/s 1B

Adjusted Short Term Through and Out Revenues
Used in the development of 2009 PTF Revenue Requirements
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects

		CL&P	PSNH	WMECO	TOTAL	Reference
1	2009 Through and Out Revenues	1,202,987	207,037	91,713	1,501,737	FF1 pg 328.1 - 330.1
2	Less: LT Revs	-	-	-	-	
3	ST T/O Revenues (Line 1-2)	1,202,987	207,037	91,713	1,501,737	
4	RTO ROE Adjustm.	-	-	-	-	
5	NET ST T/O Revs.	1,202,987	207,037	91,713	1,501,737	
6	Pre-1997 PTF Plant	387,837,863	96,744,902	65,630,687	550,213,452	
7	Post-1996 PTF Plant	1,824,954,421	283,386,061	90,343,016	2,198,683,498	Attachment A
8	Total PTF Plant (line 6 + 7)	2,212,792,284	380,130,963	155,973,703	2,748,896,950	
9	Ratio of Pre to Total (Line 6 / 8)	17.53%	25.45%	42.08%		
10	Ratio of Post to Total (Line 7 / 8)	82.47%	74.55%	57.92%		
		100.00%	100.00%	100.00%		
	Revenue Credits Allocated to Pre-1997 and Post-1996 Revenue Requirements:					
11	Pre-1997 Revenue Credit (line 5 * 9)	210,884	52,691	38,593	302,168	to w/s 1A
12	Post-1996 Revenue Credit (line 5 * 10)	992,103	154,346	53,120	1,199,569	to w/s 1B
13	Total Revenue Credit (line 11+12)	1,202,987	207,037	91,713	1,501,737	

Attachment D

Northeast Utilities Systems Companies
Adjusted Capitalization
To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects
Calendar Year 2009- Year End

Line No.	**Long Term Debt**	**CL&P Year End**	**PSNH Year End**	**WMECO Year End**	**Reference**
1	Outstanding Bonds (A/C 221 & 224)	2,341,017,150	837,285,000	248,832,680	FF1 page 257 ln 33
2	Premium on LTD (225)	-	-	-	FF1 page 112 ln. 22
3	Discount on LTD (226)	4,908,103	1,030,112	448,530	FF1 page 112 ln. 23
4	Debt Expense (181)	19,014,006	8,244,798	2,026,042	FF1 page 111 ln. 69
5	Gain on Reacquired Debt (257)	-	-	-	FF1 page 113 ln. 61
6	**Total LTD (Year End) line 1+2-3-4+5)**	**2,317,095,041**	**828,010,090**	**246,358,108**	
7	**Total LTD (Beginning of Year / End of Year Average)**	**2,161,555,916**	**753,477,123**	**246,457,536**	(Line 6 + prior YE capitalization) / 2
8	Annual Amort of Prem Disc. & Exp. (A/C 428 minus A/C 429)	1,809,210	971,874	202,557	FF1 page 117 ln. 63 minus ln. 65
9	Annual Amort of Gain on Reacquired Debt (A/C 429.1)	0	-	-	FF1 page 117 ln. 66
10	Annual Interest Cost (A/C 207)	134,305,038	34,249,076	14,147,300	FF1 page 257 ln. 33 + page 257, line 33 footnote - PCRB Interest
11	**Total Annual Cost (line 8-9+10)**	**136,114,248**	**35,220,950**	**14,349,857**	
12	**LTD Cost of Capital (line 11/7)**	**6.30%**	**4.67%**	**5.82%**	
	Preferred Stock				
13	Outstanding Stock (204)	116,200,000	-	-	FF1 page 112 ln. 3
14	Premium on PS (207)	820,027	-	-	G/L
15	Discount on PS (213)				
16	Unamortized Issue Expense (213)	405,148	-	-	FF1 page 112 ln. 10
17	**Net Proceeds (line 13+14-15-16)**	**116,614,879**	**-**	**-**	
18	Issue Expense Amortization (A/C 214)	50,643	-	-	FF1 page 112, ln. 10 (diff. in py & cy)
19	Dividend (A/C 437)	5,558,610	-	-	FF1 page 118 ln. 25
20	**Annual Expense (line 18+19)**	5,609,253	**-**	**-**	
21	**PS Cost of Capital (line 20/17)**	**4.81%**	**-**	**-**	
22	Proprietary Capital	2,489,382,451	727,445,198	246,807,728	FF1 page 112 ln. 16
23	**Common Equity (line 22-17)**	2,372,767,572	727,445,198	246,807,728	

Adjusted 2009 AFUDC Equity Amortization in Depreciation

To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects

PRE-97

	a	b	c	d	e	f	g
	Transmission	PTF Allocator	Transmission PTF level (a*b)	General Transmission	PTF Allocator	General PTF level (d*e)	Total at PTF level (c+f)
CL&P	3,144,044.0	15.6805%	493,002	46,096	15.6805%	7,228	500,230
PSNH	146,272.0	23.9025%	34,963	8,244	23.9025%	1,971	36,934
WMECO	43,088.0	37.9026%	16,331	983	37.9026%	373	16,704
	3,333,404		544,296	55,323		9,572	553,868

Adjusted 2009 AFUDC Equity Amortization in Depreciation

To Reflect ISO-NE's Final Schedule 12C Determinations for the Middletown-Norwalk and Glenbrook Cables Projects

POST-96

	a	b	c	d	e	f	g
	Transmission	PTF Allocator	Transmission PTF level (a*b)	General Transmission	PTF Allocator	General PTF level (d*e)	Total at PTF level (c+f)
CL&P	3,144,044	73.7840%	2,319,801	46,096	73.7840%	34,011	2,353,812
PSNH	146,272	70.0153%	102,413	8,244	70.0153%	5,772	108,185
WMECO	43,088	52.1743%	22,481	983	52.1743%	513	22,994
	3,333,404		2,444,695	55,323		40,296	2,484,991

Note: This worksheet represents the "C" component of the Federal & State Income Tax Formula.

Norwood Municipal Light Department

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: 5/26/2011

Revenue Requirements for (year): 2010

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)	2,566,616	(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)	2,566,616	(j)=(f)-(g)+(h)+(i)
Forecasted Incremental Transmission Revenue Requirements			0	(m)
Annual True-up			79,600	(n)
Interest Charge on Annual True-up	-	(l)	3,909	(o)
Total = (e) + (j) + (k) + (l) + (m) + (n) + (o)	0	(p)	2,650,125	(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:			2,650,125	(r) = (p)+(q)

RNS Rate

Norwood Municipal Light Department

Annual Revenue Requirements of pre-1997 & post-1996 PTF
for costs in 2009 06/10-05/11

Line No.		Attachment F Reference Section:	Pre 1997	Post 1996	Reference
I.	INVESTMENT BASE				
1	Transmission Plant	I (A)(1)(a)	0	13,243,847	Worksheet 3, line 1 column 5
2	General Plant	I (A)(1)(b)	0	271,790	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	13,515,637	
5	Accumulated Depreciation	I (A)(1)(d)	0	3,205,899	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	10,309,738	
10	Prepayments	I (A)(1)(h)	0	3,878	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	37,613	Worksheet 3, line 24 column 5
13	Total Investment Base (Line 9+11+12+13)		0	10,351,229	
II.	REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	I (A)	0	828,098	Worksheet 2
15	Depreciation Expense	I (B)	0	401,234	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	24,315	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	I (G)	0	62,669	Worksheet 4, line 13 column 5
21	Administrative & General Expense	I (H)	0	238,233	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 Ta	I (N)	0	0	Txm related Acct 456
28	Transmission Rents Received from Electric Propert	I (O)	0	0	Txm related Acct 454-rent
29	Total Revenue Requirements (Line 14 thru 28)		0	2,487,016	

III. CURRENT CALENDAR YEAR ESTIMATED INCREMENTAL REVENUE REQUIREMENT

30	Carrying Charge Factor Base Revenue Requirement Numerator	2,428,755
31	Post-2003 Enhanced Return Addition to Revenue Requirement	-
32	Total Post-96 PTF Revenue Requirement	2,428,755
33	Post-96 PTF Transmission Plant in Service	13,243,847
34	Post-96 Carrying Charge Factor (Post-96 CCF)	18.8%
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 2010

1	2010 Actual Annual RR			0	2,566,616	Input Panel Subtotals
2	2010 Est. Transmission Revenue Requirements (as billed)	6/10-05/11	Appendix C	0	2,487,016	ATRR - Prior Year
3	True-up (Over)/Under (Line 1 - Line 2)			0	79,600	

	(Overcollection)/Undercollection
Pre'97	$0
Post'96	$79,600

Initial Billing Period	Pre 1997 Balance	Post 1996 Balance	FERC Monthly Interest Rate	Pre 1997 Interest	Post 1996 Interest
June 2008	$0	$79,600	0.56%	$0	$446
July 2008	0	80,046	0.45%	0	$360
August 2008	0	80,046	0.45%	0	$360
September 2008	0	80,046	0.44%	0	$352
October 2008	0	81,118	0.42%	0	$341
November 2008	0	81,118	0.41%	0	$333
December 2008	0	81,118	0.42%	0	$341
January 2009	0	82,132	0.38%	0	$312
February 2009	0	82,132	0.34%	0	$279
March 2009	0	82,132	0.38%	0	$312
April 2009	0	83,036	0.28%	0	$233
May 2009	0	83,036	0.29%	0	$241
		Total Interest		$0	$3,909
		True-Up		$0	$79,600
		Total TU & Int		**$0**	**$83,509**

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 26, 2011

Revenue Requirements for (year): Calendar Year 2010

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)	2,566,616	(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)	2,566,616	(j)

Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:	2,566,616	(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: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)	2,566,616	(l)=(k)+(b)+(g)-(h)

Calendar Year 2010

🟨 Shading denotes an input

Line No.	I. INVESTMENT BASE	Attachment F Reference *Section:*	Norwood	Reference
1	Transmission Plant	(A)(1)(a)	15,288,499	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	291,308	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)		15,579,807	
5	Accumulated Depreciation	(A)(1)(d)	3,407,446	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)		12,172,361	
10	Prepayments	(A)(1)(h)	2,561	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)	31,591	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		12,206,513	
II.	REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	976,521	Worksheet 2
15	Depreciation Expense	(B)	379,742	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)	25,158	*Worksheet 4, line 17 column 5*
20	Operation & Maintenance Expense	(G)	51,912	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	200,816	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)		2,566,616	

Norwood Municipal Light Department
Annual Revenue Requirements
Calendar Year 2010

▨ Shading denotes an input

		CAPITALIZATION 12/31/2007	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
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	$	61,150,000	100.00%		8.00%	0.00%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0800

(b) Federal Income Tax

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

$$= \frac{(0.0000 + (0 + 0) / 12{,}206{,}513) \times 0)}{(1 - 0)}$$

$$= 0.0000000$$

(c) State Income Tax

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

$$= \frac{(0.0000 + (0 + 0) / 12{,}206{,}513) + 0.0000000)* 0}{(1 - 0)}$$

$$= 0.0000000$$

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

		(PTF)	
INVESTMENT BASE	$	12,206,513	From Worksheet 1
x Cost of Capital Rate		0.0800000	
= Investment Return and Income Taxes		976,521	To Worksheet 1

Sheet: Worksheet 3a

Norwood Municipal Light Department

Calendar Year 2010

🟨 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)
	Transmission Plant						
1	Transmission Plant	$ 15,288,499		15,288,499		15,288,499	Line 1, Worksheet 5
2	General Plant	4,142,412	9.3926% (a)	389,080	74.8709%	291,308	Page 8B line 29(g)
3	Total (line 1+2)			15,677,579		15,579,807	
4	Transmission Plant Held for Future Use	0		0	74.8709%	0	None known
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	4,440,513		4,440,513	74.8709%	3,324,652	Page 8A, line 31(g) less Page 16, line 31(g)
6	General Plant Accum.Depreciation	1,177,334	9.3926% (a)	110,582	74.8709%	82,794	Page 8B, line 29(g) less Page 17, line 29(g)
7	Total (line 5+6)			4,551,095		3,407,446	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	0	30.8491% (c)	0	74.8709%	0	None known
9	Accumulated Deferred Taxes (190)	0	30.8491% (c)	0	74.8709%	0	None known
10	Total (line 8+9)			0		0	
11	Transmission loss on Reacquired Debt	0	30.8491% (c)	0	74.8709%	0	None known
	Other Regulatory Assets						
12	FAS 106	0	9.3926% (a)	0	74.8709%	0	None known
13	FAS 109	0	30.8491% (c)	0	74.8709%	0	None known
14	Other Regulatory Liabilities (254.DK)	0	30.8491% (c)	0	74.8709%	0	
15	Total (line 12+13+14)			0		0	
16	Transmission Prepayments	36,417	9.3926% (a)	3,421	74.8709%	2,561	Assumed none
17	Transmission Materials and Supplies	0		0	74.8709%	0	Assumed none
18	Cash Working Capital						
19	Operation & Maintenance Expense					51,912	Worksheet 1, Line 20
20	Administrative & General Expense					200,816	Worksheet 1, Line 21
21	Transmission Support Expense					0	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					252,728	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					31,591	

(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 2010

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	Mass DTE AR Reference for col (1)
	Depreciation Expense						
1	Transmission Depreciation	496,784		496,784	74.8709%	371,947	Page 16, line 31(d)
2	General Depreciation	110,845	9.3926% (a)	10,411	74.8709%	7,795	Page 17, line 29(d)
3	Total (line 1+2)			507,195		379,742	
4	Amortization of Loss on Reacquired Debt	0	30.8491% (c)	0	74.8709%	0	None known
5	Amortization of Investment Tax Credits	0	30.8491% (c)	0	74.8709%	0	None known
	Property Taxes *						
6	Transmission Property Taxes	1,100,000 (d)	100.0000%	1,100,000	84.7697%	932,467	DTE, p. 21 line 24
7	General Property Taxes	0	2.2482% (a)	0	84.7697%	0	DTE, p. 21 line 24
8	Total (line 6+7)			1,100,000		932,467	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	4,503,363		4,503,363	0.748709	3,371,708	Page 40, line 50(b)
10	Transmission of Electricity by Others - #565	4,096,414		4,096,414	0.748709	3,067,022	Page 40, line 38(b)
11	Load Dispatching - #561	175,298		175,298	0.748709	131,247	Page 40, line 34(b)
12	**Station Expenses & Rents - #562 / #567	162,316		162,316	0.748709	121,527	Page 40, line 35(b) 40(b)
13	O&M less lines 10, 11 & 12	69,335		231,651	74.8709%	51,912	
	Transmission Administrative and General						
14	Administrative and General	2,518,698					Page 42, line 6(b)
15	*less Property Insurance (#924)*	148,820					Page 41, line 47(b)
16	*less Regulatory Commission Expenses (#928)*	*0*					Page 41, line 50(b)
17	*less General Advertising Expense (#930.1)*	3,045					*assumed none*
18	Subtotal [line 14 minus (15 thru 17)]	2,366,833	9.3926% (a)	222,307	74.8709%	166,443	
19	***PLUS** Property Insurance alloc. using Plant Allocatior*	*148,820*	*30.8491% (c)*	45,910	74.8709%	34,373	
20	***PLUS** Regulatory Comm. Exp. (FERC Assessments)*	*0*	*30.8491% (c)*	0	74.8709%	0	
21	***PLUS** Trans. Related General Advertising Expense*	*0*	*30.8491% (c)*	0	74.8709%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*2,515,653*		*268,217*		*200,816*	
23	*Payroll Tax Expense*	357,751	*9.3926% (a)*	*33,602*	*74.8709%*	*25,158*	

(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 2010

Line No.			Mass DTE AR Reference
	PTF Transmission Plant Allocation Factor	**Norwood**	
1	PTF Transmission Investment	15,288,499	See Worksheet
2	Total Transmission Investment	20,419,808	Page 8A, line 31(g)
3	Percent Allocation (Line 1/Line 2)	74.8709%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	264,972	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)	264,972	
7	Total Wages and Salaries	3,252,280	Page 42, line 24 (c)
8	Administrative and General Wages and Salaries	431,206	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)	2,821,074	
11	Percent Allocation (Line 6/Line 10)	9.3926%	
	Plant Allocation Factor		
12	Total Transmission Investment	20,419,808	Line 2
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	389,080	*Worksheet 3, Line 2*
14	*= Revised Numerator (Line 12 + Line 13)*	20,808,888	
15	Total Plant in Service	67,453,846	Page 8B, line 30 (g)
16	Percent Allocation (Line 14 / Line 15)	30.8491%	

Sheet: Worksheet 6 of 7

Affiliated Company Wages and Salaries

▨ Shading denotes an input

Calendar Year 2010

Line		Norwood
"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

Calendar Year 2010

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)	TOTAL 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

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: 5/16/2011

Revenue Requirements for (year): 2010

Customer: NSTAR Electric Company

Customer's NABs Number: 3

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

DUNs number of Participant responsible for customer's billing: 6951552

		Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	=	53,049,787	(a)	99,396,553	(f)
Total of Attachment F - Section J - Support Revenue		(674,892)	(b)	-	(g)
Total of Attachment F - Section K - Support Expense		2,244,084	(c)	-	(h)
Total of Attachment F - Section L through O		(226,355)	(d)	(411,998)	(i)
Sub Total - Sum (A through I) - J + K + (L through O)		54,392,624	(e)=(a)-(b)+(c)+(d)	98,984,555	(j)=(f)-(g)+(h)+(i)
Forecasted Incremental Transmission Revenue Requirements		-	n/a	6,721,127	(m)
Annual True-up		(723,854)	(k)	2,616,506	(n)
Interest Charge on Annual True-up		(24,121)	(l)	87,191	(o)
Total = (e) + (j) + (k) + (l) + (m) + (n) + (o)		53,644,648	(p)	108,409,378	(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:				$ 162,054,026	(r) = (p)+(q)

NSTAR Electric Company
Annual Revenue Requirements of pre-1997 & post-1996 PTF
for costs in 2010 06/10-05/11

Line No.	I. INVESTMENT BASE	Attachment F Reference	Pre 1997	Post 1996	Reference
		Section:			
1	Transmission Plant	II (A)(1)(a)	$ 398,085,147	$ 724,571,071	Page 4, line 2
2	General Plant	II (A)(1)(b)	3,877,470	7,057,549	Page 4, line 3
3	Plant Held For Future Use	II (A)(1)(c)	-	798,633	Page 4, line 5
4	Total Plant		$ 401,962,617	$ 732,427,252	Sum Lines 1 thru 3
5	Accumulated Depreciation	II (A)(1)(d)	(111,233,347)	(202,460,575)	Page 4, line 9
6	Accumulated Deferred Income Taxes	II (A)(1)(e)	(82,259,378)	(149,723,814)	Page 4, line 14
7	Loss On Reacquired Debt	II (A)(1)(f)	1,539,238	2,801,633	Page 4, line 15
8	Other Regulatory Assets	II (A)(1)(g)	1,996,273	3,633,502	Page 4, line 20
9	Net Investment		$ 212,005,404	$ 386,677,999	Sum Lines 4 thru 8
10	Prepayments	II (A)(1)(h)	562,130	1,023,158	Page 4, line 21
11	Materials & Supplies	II (A)(1)(II)	850,212	1,547,507	Page 4, line 22
12	Cash Working Capital	II (A)(1)(j)	1,266,579	1,948,335	Page 4, line 29
13	Total Investment Base		$ 214,684,325	$ 391,197,000	Sum Lines 9 thru 12
	II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	II (A)	$ 28,257,973	$ 54,271,911	Page 3, Line 26
15	Depreciation Expense	II (B)	8,976,990	16,339,404	Page 5, Line 4
16	Amortization of Loss on Reacquired Debt	II (C)	185,088	336,886	Page 5, Line 5
17	Investment Tax Credit	II (D)	(104,484)	(190,175)	Page 5, Line 6
18	Property Taxes	II (E)	6,939,988	12,631,769	Page 5, Line 8
19	Payroll Tax Expense	II (F)	230,792	420,074	Page 5, Line 24
20	Operation & Maintenance Expense	II (G)	5,473,365	9,962,305	Page 5, Line 14
21	Administrative & General Expense	II (H)	3,090,075	5,624,378	Page 5, Line 23
22	Transmission Related Integrated Facilities Charge	II (II)	-	-	
23	Transmission Support Revenue	II (J)	(674,892)	-	Page 7, Line 13
24	Transmission Support Expense	II (K)	2,244,084	-	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)	(226,355)	(411,998)	OATT Schedule 8 TOUT
28	Transmission Rents Received from Electric Property	II (O)	-	-	
29	Total Revenue Requirements		$ 54,392,624	$ 98,984,555	Sum Lines 14 thru 28
	III. CURRENT CALENDAR YEAR ESTIMATED INCREMENTAL REVENUE REQUIREMENT				
30	Carrying Charge Factor Base Revenue Requirement Numerator			$ 99,396,553	Line 29 - Line 27
31	Post-2003 Enhanced Return Addition to Revenue Requirement			-	
32	Total Post-96 PTF Revenue Requirement			$ 99,396,553	Sum Lines 30 thru 31
33	Post-96 PTF Transmission Plant in Service			$ 724,571,071	Line 1
34	Post-96 Carrying Charge Factor (Post-96 CCF)			0.137179853	Line 32 / Line 33
35	Forecasted Post-96 PTF Plant Additions			$ 48,995,000	
36	Forecasted Post-96 Localized PTF Plant Additions			-	
37	Forecasted Post-96 Pool-Supported PTF Plant Additions			48,995,000	Sum Lines 35 thru 36
38	Post-96 Estimated Incremental Revenue Requirement			$ 6,721,127	Line 34 * Line 37

NSTAR Electric Company
FERC Interest Calculation associated with Under / (Over)
True-up and Interest Calculation 06/10-05/11

1	2010 Est. Transmission Revenue Requirements (as billed)	6/10-05/11	Appendix C	55,116,478	96,368,049	ATRR - Prior Year
2	2010 Actual Annual RR			54,392,624	98,984,555	Input Panel Subtotals
3	True-up Over/(Under) (Line 1 - Line 2)			723,854	(2,616,506)	

	(Overcollection)/Undercollection
Pre'97	($723,854)
Post'96	$2,616,506

Initial Billing Period	Pre 1997 Balance	Post 1996 Balance	FERC Monthly Interest Rate	Pre 1997 Interest	Post 1996 Interest
June 2010	$ (723,854)	$ 2,616,506	0.27%	$ (1,954)	$ 7,065
July 2010	(725,809)	2,623,570	0.28%	(2,032)	7,346
August 2010	(725,809)	2,623,570	0.28%	(2,032)	7,346
September 2010	(725,809)	2,623,570	0.27%	(1,960)	7,084
October 2010	(731,833)	2,645,346	0.28%	(2,049)	7,407
November 2010	(731,833)	2,645,346	0.27%	(1,976)	7,142
December 2010	(731,833)	2,645,346	0.28%	(2,049)	7,407
January 2011	(737,907)	2,667,302	0.28%	(2,066)	7,468
February 2011	(737,907)	2,667,302	0.25%	(1,845)	6,668
March 2011	(737,907)	2,667,302	0.28%	(2,066)	7,468
April 2011	(743,884)	2,688,907	0.27%	(2,008)	7,260
May 2011	(743,884)	2,688,907	0.28%	(2,083)	7,529
		Total Interest		$ (24,121)	$ 87,191
		True-Up		(723,854)	2,616,506
		Total TU & Int		**$ (747,976)**	**$ 2,703,696**

NSTAR Electric Company
2011 Forecast PTF Capital Additions

Line #	RSP Project ID	Project Description		Amount
1	695/830/831	Carver Sta	$	3,000
2	963	Holbrook Breaker 11		12,000
3	1067	Tremont Station Upgrades		683,000
4	1066	BPS Program Needham Upgrade		5,848,000
5	842/1153	West Framingham Capacitor Installation Station Work		1,000
6	904	Mystic Sta 250 Brk Repl 2010		21,000
7	301	Lexington - Waltham 115kV Line (Reconductor 115kV Line 320-507/508)		4,197,000
8	1113	K St Breaker and Tie Bus		468,000
9	969	Chelsea Cap bank		1,513,000
10	1206	230kV breaker for 282-602 at jet site Sta 446		130,000
11	1201	128-518 reconductoring		925,000
12		Subtotal: RSP Projects	$	13,801,000
13		Pump Plant Upgrades Needham & Mystic	$	7,000
14		TRV Mitigation STA 211		21,000
15		Static Wires (211-503/4/456-522, 148-522,112,107,451-536)		1,000
16		Cross Arms (319.211-508,240-510)		121,000
17		Station 250 Unit 8 & 9 LFCB's		34,000
18		STA 980 Transmission Breaker Repla		95,000
19		Relocate 115kV Terminals 447-508-50		7,000
20		Heat Exchangers & Misc. PP Upgrades		3,620,000
21		SEECO Switches		97,000
22		Replace Batteries		55,000
23		STA 509 345kV Transmission Breaker Replacement CB 102,103,105,106		43,000
24		STA 509 TRV Mitigation		55,000
25		STA 456 TRV Mitigation		127,000
26		STA 980 DFR Replacement		1,000
27		STA 342 115kV Breaker Repl.		291,000
28		STA 150 115kV Breaker Repl.		83,000
29		STA 385T 115kV Breaker Repl.		139,000
30		STA 446 345kV Breaker Installation		36,000
31		PTC Heat Exch - station work		404,000
32		Carver 345A, install in 2011		6,062,000
33		ROW Roads		1,861,000
34		ROW Gates		702,000
35		SEECO Switch Replacement		959,000
36		Counterpoise Replacement		1,412,000
37		Static Wire Replacement		3,281,000
38		Polymer Insulator and Lightning Replacement		1,427,000
39		Structure Replacements		302,000
40		Cathodic Protection: Replace 12 Anodes Replace 35 P-Cells		601,000
41		Replace Heat Exchangers (STA 148, 509, 250 & 514)		1,929,000
42		BPS Support- NSTAR terminals Line 342		228,000
43		BPS Support- NSTAR terminals Line 335		228,000
44		BPS Support- NSTAR terminals Line 323, 357		456,000
45		BPS Support- NSTAR terminals Line 191		228,000
46		Replace Portion of 21 115kV Breakers at various substations-Central		1,267,000
47		Replace Portion of 21 115kV Breakers at various substations-West		3,425,000
48		Replace 3 345kV Breakers at Carver Install Only		1,045,000
49		Replace Portion of 25 115kV Disconnects-Central		185,000
50		Replace Portion of 25 115kV Disconnects-South		128,000
51		Install Portion of 175 Meters at various locations-West		116,000
52		Replace Transmission Batteries-Central		138,000
53		Install Synchro-phasor upgrades at Carver, K Street, West Medway, and Mystic St		484,000
54		Install new DFR at STA 350 & 496, Upgrade DFR's at STA 958, 250		378,000
55		TRV mitigation Sta 110,		10,000
56		Walpole reactor		3,000
57		Replace Section Line 372		3,102,000
58		Subtotal: Other Projects	$	35,194,000
59		Total Forecast PTF Additions	$	48,995,000

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 1

Submitted on: May 16, 2011
Revenue Requirements for (year): 2010
Customer: NSTAR Electric Company
Customer's NABs Number: 3
Name of Participant responsible for customer's billing: NSTAR Electric Company
DUNs number of Participant responsible for customer's billing: 6951552

		Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	=	$ 53,049,787	(a)	$ 99,396,553	(f)
Total of Attachment F - Section J - Support Revenue	=	674,892	(b)	-	(g)
Total of Attachment F - Section K - Support Expense	=	2,244,084	(c)	-	(h)
Total of Attachment F - Sections L-O	=	(226,355)	(d)	(411,998)	(i)
Sub Total - Sum (A through H) - J + K+ (L through O)	=	$ 54,392,624	(e)=(a)-(b)+(c)+(d)	$ 98,984,555	(j)
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:				$ 153,377,179	(k) = (e) + (j)

ISO New England Inc.
FERC Electric Tariff No. 3
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per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3
NSTAR Electric Company
Page 2

Line	Investment Base	Attachment F Reference *Section:*	Pre-1997	Post-1996	Reference
	Col.A	Col.B	Col.C	Col.D	Col.E
1	Transmission Plant	II (A)(1)(a)	$ 398,085,147	$ 724,571,071	Page 4, line 2
2	General Plant	II (A)(1)(b)	3,877,470	7,057,549	Page 4, line 3
3	Plant Held For Future Use	II (A)(1)(c)	-	798,633	Page 4, line 5
4	Total Plant		401,962,617	732,427,252	Sum Lines 1 thru 3
5	Accumulated Depreciation	II (A)(1)(d)	(111,233,347)	(202,460,575)	Page 4, line 9
6	Accumulated Deferred Income Taxes	II (A)(1)(e)	(82,259,378)	(149,723,814)	Page 4, line 14
7	Loss On Reacquired Debt	II (A)(1)(f)	1,539,238	2,801,633	Page 4, line 15
8	Other Regulatory Asssets	II (A)(1)(g)	1,996,273	3,633,502	Page 4, line 20
9	Net Investment		212,005,404	386,677,999	Sum Lines 4 thru 8
10	Prepayments	II (A)(1)(h)	562,130	1,023,158	Page 4, line 21
11	Materials & Supplies	II (A)(1)(II)	850,212	1,547,507	Page 4, line 22
12	Cash Working Capital	II (A)(1)(j)	1,266,579	1,948,335	Page 4, line 29
13	Total Investment Base		$ 214,684,325	$ 391,197,000	Sum Lines 9 thru 12
14	Revenue Requirement				
15	Investment Return and Income Taxes	II (A)	$ 28,257,973	$ 54,271,911	Page 3, Line 26
16	Depreciation Expense	II (B)	8,976,990	16,339,404	Page 5, Line 4
17	Amortization of Loss on Reacquired Debt	II (C)	185,088	336,886	Page 5, Line 5
18	Investment Tax Credit	II (D)	(104,484)	(190,175)	Page 5, Line 6
19	Property Taxes	II (E)	6,939,988	12,631,769	Page 5, Line 8
20	Payroll tax Expense	II (F)	230,792	420,074	Page 5, Line 25
21	Operation & Maintenance Expense	II (G)	5,473,365	9,962,305	Page 5, Line 14
22	Administrative & General Expense	II (H)	3,090,075	5,624,378	Page 5, Line 24
23	Transmission Related Integrated Facilities Charge	II (I)	-	-	
24	Transmission Support Revenue	II (J)	(674,892)	-	Page 7, Line 13
25	Transmission Support Expense	II (K)	2,244,084	-	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)	(226,355)	(411,998)	OATT Schedule 8 TOUT
29	Transmission Rents Received for Electric Property	II (O)	-	-	
30	Total Revenue Requirements		$ 54,392,624	$ 98,984,555	Sum Lines 15 thru 29
31	Total			$ 153,377,179	Sum Line 30, Col C & Col D

ISO New England Inc.
FERC Electric Tariff No. 3
Open Access Transmission Tariff
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per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3
NSTAR Electric Company
Page 3

Line	Description	Capitalization 12/31/10	Cost of Capital	Weighted Cost of Capital	Weighted Equity Portion
	Col.A	Col.B	Col.C	Col.D	Col.E
1	Long-Term Debt	$ 1,609,990,151	5.3862%	2.2798%	
2	Preferred Stock	43,000,000	4.5581%	0.0515%	0.0515%
3	Common Equity	2,150,708,925	11.6400%	6.5816%	6.5816%
4	Total Investment Return	$ 3,803,699,076		8.9129%	6.6331%

ROE per Attachment F Page 242 http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/index.html

5	**Federal Income Tax (FIT)**	**Pre-97**	**Post 96**	
6	A= Preferred & Equity Return	6.63308%	6.63308%	Preferred & Equity Return
7	B= Transmission Related Amortization of ITC	$ (104,484)	$ (190,175)	Page 2, Line 18
8	C= Equity AFUDC Component of Depreciation Expense	$ -	$ -	Equity AFUDC Component of Tramssion Dep Exp
9	D= Transmission Investment Base	$ 214,684,325	$ 391,197,000	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)	3.54545%	3.54548%	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)	0.70422%	0.70422%	State IncomeTax
15	Allowed Return	13.16257%	13.16260%	line 4, Col.D + Line 11 + Line 14
16	D= Transmission Investment Base	$ 214,684,325	$ 391,197,000	Page 2, Line 8
17	**Return**	$ 28,257,973	$ 51,491,715	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		0.56543%	line 19 * line 3 / line 4
21	Additional FIT		0.30446%	Incremental FIT = (a' x FT)/(1-FT)
22	Additional SIT		0.06047%	Incremental SIT = (A' + FIT)(ST)/(1-ST)
23	Additional Return		0.93036%	Sum lines 20 thru 22
24	Post 2003 PTF net Investment		$ 298,830,530	Page 8, line 16
25	Additional 100 bp Return Post 2003 PTF Investment		$ 2,780,196	Line 23 * Line 24
26	Total Return	$ 28,257,973	$ 54,271,911	Line 17 + Line 25

27	**Incremental return for PTF 50 Basis Point Adder**	Capitalization 12/31/10	Cost of Capital	Weighted Cost of Capital	Weighted Equity Portion
28	Long-Term Debt	$ 1,609,990,151	5.3862%	2.2798%	
29	Preferred Stock	43,000,000	4.5581%	0.0515%	
30	Common Equity	2,150,708,925	0.5000%	0.2827%	0.2827%
31	Total Investment Return	$ 3,803,699,076		2.6141%	0.2827%

32	**Federal Income Tax (FIT)**	**Pre-97**	**Post 96**	
33	A= Incremental Return	0.28271%	0.28271%	Equity Return
34	B= Transmission Related Amortization of ITC	$ (104,484)	$ (190,175)	Page 2, Line 18
35	C= Equity AFUDC Component of Depreciation Expense	$ -	$ -	Equity AFUDC Component of Tramssion Dep Exp
36	D= Transmission Investment Base	$ 214,684,325	$ 391,197,000	Page 2, Line 8
37	FT = Federal Income Tax Rate	35%	35%	Federal Income Tax Rate
38	FIT = (A+[C+B)/D])(FT)/(1-FT)	0.12602%	0.12605%	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)	0.02503%	0.02504%	State IncomeTax
42	Allowed Return	0.43377%	0.43380%	line 33 + Line 38 + Line 41
43	D= Transmission Investment Base	$ 214,684,325	$ 391,197,000	Transmission Investment Base: Page 2, line 13
44	Return 50 bp Adder	$ 931,232	$ 1,697,027	Line 42 * Line 43
45	Total Return 50 bp Adder		$ 2,628,259	Line 44 Pre-97 + Line 44 Post 96
46	Total Incremental Return		$ 5,408,455	Line 25 + Line 45

ISO New England Inc.
FERC Electric Tariff No. 3
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per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3
NSTAR Electric Company
Page 4

						Pre-97 PTF		Post-96 PTF		
Line	Description	Total	Allocation Factors		Transmission Allocated	Allocation Factor (b)	Pre-97 PTF Allocated	Allocation Factor (b)	Post 96 PTF Allocated	FERC Form 1 Reference for col (1)
			Wage/Plant			Pre-97 PTF		Post 96 PTF		
	Col.A	Col.B	Col.C		Col.D	Col.E	Col.F	Col.G	Col.H	Col.I
					(Col.B x Col.C)		(Col.D x Col.E)		(Col.D x Col.G)	
1	Transmission Plant									
2	Transmission Plant (exc SCADA)	$ 1,282,023,284			$1,282,023,284		$ 398,085,147		$ 724,571,071	Page 6, Line 3
3	General Plant	184,521,250	6.7674%	(a)	12,487,303	31.0513%	3,877,470	56.5178%	7,057,549	FF1 207.99g
4	Total Transmission Plant				$1,294,510,586		$ 401,962,617		$ 731,628,619	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)	$ (353,728,631)			$ (353,728,631)	31.0513%	$ (109,837,338)	56.5178%	$ (199,919,640)	Page 8, Line 11
8	General Plant Accum.Depreciation	(66,433,323)	6.7674%	(a)	(4,495,813)	31.0513%	(1,396,008)	56.5178%	(2,540,935)	FF1 219.28b
9	Total Transmission Acc Dep				$ (358,224,444)		$ (111,233,347)		$ (202,460,575)	Sum line 7 thru line 8
10	Transmission Accumulated Deferred Taxes									
11	Accumulated Deferred Taxes (282) (d)	$ (602,787,456)	23.8919%	(c)	$ (144,017,470)	31.0513%	$ (44,719,297)	56.5178%	$ (81,395,506)	Line 35
12	Accumulated Deferred Taxes (283) (e)	(580,752,748)	23.8919%	(c)	(138,752,956)	31.0513%	(43,084,597)	56.5178%	(78,420,118)	Line 38
13	Accumulated Deferred Taxes (190)	74,736,516	23.8919%	(c)	17,855,985	31.0513%	5,544,516	56.5178%	10,091,810	FF1 234.18c
14	Total				$ (264,914,441)		$ (82,259,378)		$ (149,723,814)	Sum line 11 thru line 13
15	Transmission loss on Reacquired Debt	$ 20,747,945	23.8919%	(c)	$ 4,957,081	31.0513%	$ 1,539,238	56.5178%	$ 2,801,633	FF1 111.81c
16	Other Regulatory Assets									
17	FAS 106	$ 1,546,517	6.7674%	(a)	$ 104,659					FF1 232.1.33f
18	ASC 740 Regulatory Asset (FAS 109)	32,986,993	23.8919%	(c)	7,881,225					FF1 232.1.23f
19	ASC 740 Regulatory Liability (FAS 109)	(6,516,564)	23.8919%	(c)	(1,556,932)					FF1 278.2f
20	Total	$ 28,016,946			$ 6,428,952	31.0513%	$ 1,996,273	56.5178%	$ 3,633,502	Sum line 17 thru line 19
21	Transmission Prepayments	$ 26,750,697	6.7674%	(a)	$ 1,810,328	31.0513%	$ 562,130	56.5178%	$ 1,023,158	FF1 111.57c
22	Transmission Materials and Supplies	$ 2,738,088	100.0000%		$ 2,738,088	31.0513%	$ 850,212	56.5178%	$ 1,547,507	FF1 227.8c + 5c(footnote)
23	Cash Working Capital									
24	Operation & Maintenance Expense						$ 5,473,365		$ 9,962,305	Page 5, line 14
25	Administrative & General Expense						3,090,075		5,624,378	Page 5, line 24
26	Transmission Support Expense						1,569,192		-	Page 7, line 14
27	Total						$ 10,132,631		$ 15,586,683	Sum line 24 thru line 26
28	45 day rule						0.125		0.125	= 45 / 360
29	Cash Working Capital						$ 1,266,579		$ 1,948,335	Line 27 * line 28
30	(a) Labor Allocator Page 6, Line 14	6.7674%								
31	(b) PTF Allocator Page 6, Line 4					31.0513%		56.5178%		
32	(c) Plant Allocator Page 6, Line 20	23.8919%								
33	(d) Account 282	$ 602,787,456	FF1 275.9k							
34	less amounts related to divestiture	-	FF1 275.4k							
35	Total Account 282	$ 602,787,456	Sum line 33 thru line 34							
36	(e) Account 283	$ 657,515,365	FF1 277.9k							
37	less amounts related to divestiture	(76,762,617)	FF1 277.9k(footnote)							
38	Total Account 283	$ 580,752,748	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

Shading denotes an input

					Pre-97 PTF		Post 96 PTF		
Line	Description	Total	Wage/Plant Allocation Factors	Transmission Allocated	Allocation Factor (b)	Pre-97 PTF Allocated	Allocation Factor (b)	Post 96 PTF Allocated	Reference for col (1) FF1 = FERC Form 1
	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	Depreciation Expense								
2	Transmission Depreciation	$ 28,210,616		$ 28,210,616	31.0513%	$ 8,759,763	56.5178%	$ 15,944,019	Page 8, Line 11, Col.D
3	General Depreciation	10,337,429	6.7674% (a)	699,576	31.0513%	217,227	56.5178%	395,385	FF1 336.10f
4	Total	$ 38,548,045		$ 28,910,192		$ 8,976,990		$ 16,339,404	Sum line 2 thru line 3
5	Amortization of Loss on Reacquired Debt	$ 2,494,866	23.8919% (c)	$ 596,071	31.0513%	$ 185,088	56.5178%	$ 336,886	FF1 117.64c
6	Amortization of Investment Tax Credits	$ 1,408,371	23.8919% (c)	$ 336,487	31.0513%	$ 104,484	56.5178%	$ 190,175	FF1 266.8f & 11f
7	Property Taxes								
8	Transmission Property Taxes	$ 93,546,588	23.8919% (c)	$ 22,350,072	31.0513%	$ 6,939,988	56.5178%	$ 12,631,769	FF1 263.5i
9	Transmission Operation and Maintenance								
10	Operation and Maintenance	$ 285,783,766		$285,783,766	31.0513%	$ 88,739,575	56.5178%	$ 161,518,697	FF1 321.112b
11	Transmission of Electricity by Others - #565	(243,672,391)		(243,672,391)	31.0513%	(75,663,445)	56.5178%	(137,718,275)	FF1 321.96b
12	Load Dispatching - #561 to #561.4	(15,119,037)		(15,119,037)	31.0513%	(4,694,658)	56.5178%	(8,544,947)	FF1 321.85b-.88b
13	Rents - #567	(9,365,493)		(9,365,493)	31.0513%	(2,908,107)	56.5178%	(5,293,171)	FF1 321.98b
14	O&M for RNS Tariff	$ 17,626,845		$ 17,626,845		$ 5,473,365		$ 9,962,305	Sum line 10 thru line 13
15	Transmission Administrative and General								
16	Administrative and General	$ 149,338,323							FF1 323.197b
17	less Property Insurance (#924)	(559,763)							FF1 323.185b
18	less Regulatory Commission Expenses (#928)	(8,723,785)							FF1 323.189b
19	less General Advertising Expense (#930.1)	(354,573)							FF1 323.191b
20	Subtotal	$ 139,700,202	6.7674% (a)	$ 9,454,080	31.0513%	$ 2,935,615	56.5178%	$ 5,343,238	Sum line 16 thru line 19
21	Plus Property Ins. alloc. Using Plant Allocator	559,763	23.8919% (c)	133,738	31.0513%	41,527	56.5178%	75,586	Line 17
22	Plus Regulatory Comm. Exp (Transmission FERC Assessments)	1,522,267	23.8919% (c)	363,699	31.0513%	112,933	56.5178%	205,555	FF1 350.8d
23	Plus General Advertising Expense	-	100.0000%	-	31.0513%	-	56.5178%	-	
24	Total A&G for RNS Tariff	$ 141,782,232		$ 9,951,517		$ 3,090,075		$ 5,624,378	Sum line 20 thru line 23
25	Payroll Tax Expense	$ 10,982,922	6.7674% (a)	$ 743,259	31.0513%	$ 230,792	56.5178%	$ 420,074	FF1 263.8i
26	(a) Labor Allocator Page 6, Line 14	6.7674%							
27	(b) PTF Allocator Page 6, Line 4				31.0513%		56.5178%		
28	(c) Plant Allocator Page 6, Line 20	23.8919%							

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	**PTF Transmission Plant Allocation Factor**				
2	PTF Transmission Investment	$ 398,085,147	$ 724,571,071	$ 464,076,105	Page 8, Col G lines 1,2,3
3	Total Transmission Investment excluding SCADA	$ 1,282,023,284	$ 1,282,023,284	$ 1,282,023,284	Page 8, Line 5, Col.G
4	Percent Allocation	31.0513%	56.5178%	36.1987%	Line 2 / Line 3
5	Total PTF Allocation (Pre 97 + post 96)		87.5691%		Line 4, Col.B plus Col.C
6	**Transmission Wages and Salaries Allocation Factor**				
7	Direct Transmission Wages and Salaries	$ 10,483,157			FF1 354.21b
8	Less EMC Transmission Wages and Salaries	(2,306,908)			Acct 561 Labor
9	Total Transmission Wages and Salaries	$ 8,176,249			Line 7 + Line 8
10	Total Wages and Salaries	$ 159,731,913			FF1 354.28b
11	Administrative and General Wages and Salaries	(38,913,852)			FF1 354.27b
12	Affiliated Company Wages and Salaries less A&G	-			NA
13	Total Wages and Salaries net of A&G	$ 120,818,061			Sum lines 10 thru 12
14	Percent Allocation	6.7674%			Line 9 / Line 13
15	**Plant Allocation Factor**				
16	Total Transmission Investment (exc SCADA)	$ 1,282,023,284			Line 2
17	Plus Transmission Related General Plant (Line 2 Wkst.3)	12,487,303			Page 4, Line 3, Col.D
18	Revised Numerator (Line 12 + Line 13)	$ 1,294,510,586			Line 16 + Line 17
19	Total Plant in Service	$ 5,418,195,054			FF1 207.104g
20	Percent Allocation	23.8919%			Line 18 / Line 19
21	Transmission Plant only Allocator	23.6614%			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

Line	PTF Supporting Facilities	Revenues	Expenses	Reference
	Col.B	Col.C	Col.D	
1	National Grid Support Revenues	$ 4,332		FF1 p.300 line 22 col.(b) footnote
2	Hydro Quebec Phase 2 Support	386,173		FF1 p.300 line 22 col.(b) footnote
3	EUA/NEP Station 342 Support	63,954		FF1 p.300 line 22 col.(b) footnote
4	Montaup Station 451 Support	11,779		FF1 p.300 line 22 col.(b) footnote
5	NEP Line 201-502 Medway Support	4,633		FF1 p.300 line 22 col.(b) footnote
6	Reading Lines 211-503/504 Support	160,901		FF1 p.300 line 22 col.(b) footnote
7	Transmission support revenue	43,120		FF1 p.300 line 22 col.(b) footnote
8	New England Power Co		(115,827)	FF1 p.332 line 1 col.(h)
9	Wellesley Municipal Lgt		17,983	FF1 p.332 line 3 col.(h)
10	New England Power Support		837,450	FF1 p.321 line 98 col.(b) footnote
11	Hydro Quebec Phase II NEP AC, Chester SVC		1,467,125	FF1 p.321 line 98 col.(b) footnote
12	Transmission Line Rents		37,353	FF1 p.321 line 98 col.(b) footnote
13	Total	$ 674,892	$ 2,244,084	
14	Net		$ 1,569,192	

Transmission Investment

Line	Description	12/31/09	Additions	Retirements	Reclass	Adjustment	12/31/2010
	Col.A	Col.B	Col.C	Col.D	Col.E	Col.F	Col.G
1	Pre-97 PTF(excl. SCADA)	$ 400,782,972	$ -	$ (2,697,825)	$ -	$ -	$ 398,085,147
2	Post-96 PTF not in plan (excl. SCADA)	230,465,781	32,159,126	(1,750,668)	(379,274)	-	260,494,965
3	Post-03 PTF in plan (excl. SCADA)	443,395,111	22,057,901	(1,376,906)	-	-	464,076,105
4	Non-PTF(excl. SCADA)	148,088,186	12,952,271	(600,277)	(1,073,114)	-	159,367,066
5	Sub -Total	$ 1,222,732,051	$ 67,169,298	$ (6,425,677)	$ (1,452,388)	$ -	$ 1,282,023,284
6	SCADA (Billed under Schedule 1)						
7	PTF	$ 9,327,068	$ -	$ -	$ -	$ -	$ 9,327,068
8	Non-PTF	1,943,683	-	-	-	-	1,943,683
9	Sub - Total	$ 11,270,751	$ -	$ -	$ -	$ -	$ 11,270,751
10	Total Transmission	$ 1,234,002,802	$ 67,169,298	$ (6,425,677)	$ (1,452,388)	$ -	$ 1,293,294,035
		FF1 p.206 line 58 col.(b)	FF1 p.206 line 58 col.(c)	FF1 p.207 line 58 col.(d)	FF1 p.207 line 58 col.(f)	FF1 p.207 line 58 col.(e)	FF1 p.207 line 58 col.(g)

Line	Description	Transmission Total	Less: SCADA (a)	Transmission net of SCADA	Reference for Column B
		Col.B	Col.C	Col.D	
				(Col.B - Col. C)	
11	Accumulated Depreciation	$ 357,324,350	$ 3,595,719	$ 353,728,631	FF1 p. 219, line 25, col.(b)
12	Depreciation Expense	$ 28,486,191	$ 275,575	$ 28,210,616	FF1 p. 336, line 7, col.(f)

Line	Description	Actual Per Books	
13	Post-03 PTF in Plan subject to 100 bp adder	$ 357,004,972	
14	Transmission Accum. Depreciation subject to 100 bp adder	(33,065,913)	
15	Transmission Accumulated Deferred Taxes subject to 100 bp adder	(25,108,529)	
16	Net Post-03 PTF in Plan subject to 100 bp adder	$ 298,830,530	Sum lines 13 thru 15

17 (a) Values for SCADA taken from Schedule 1 Revenue Requirement

Reading Municipal Light Plant

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: 5/16/2011

Revenue Requirements for (year): 2010

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

		Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	=	2,354	(a)	258,493	(f)
Total of Attachment F - Section J - Support Revenue		0	(b)	0	(g)
Total of Attachment F - Section K - Support Expense		235,423	(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)		237,777	(e)=(a)-(b)+(c)+(d)	258,493	(j)=(f)-(g)+(h)+(i)
Forecasted Incremental Transmission Revenue Requirements				0	(m)
Annual True-up		130,928		55,174	(n)
Interest Charge on Annual True-up		6,430		2,710	(o)
Total = (e) + (j) + (k) + (l) + (m) + (n) + (o)		375,135	(p)	316,377	(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:				691,511	(r) = (p)+(q)

Reading Municipal Light Plant
Annual Revenue Requirements of pre-1997 & post-1996 PTF
for costs in 2009 06/10-05/11

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	Pre 1997	Post 1996	Reference
1	Transmission Plant	I (A)(1)(a)	0	2,546,936	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	2,546,936	
5	Accumulated Depreciation	I (A)(1)(d)	0	722,946	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	1,823,990	
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)	13,224	1,139	Worksheet 3, line 24 column 5
13	Total Investment Base (Line 9+11+12+13)		13,224	1,825,129	
II.	REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	I (A)	1,058	146,010	Worksheet 2
15	Depreciation Expense	I (B)	0	965	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	47,232	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	877	Worksheet 4, line 13 column 5
21	Administrative & General Expense	I (H)	0	8,235	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)	105,791	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 Ta	I (N)	0	0	Txm related Acct 456
28	Transmission Rents Received from Electric Propert	I (O)	0	0	Txm related Acct 454-rent
29	Total Revenue Requirements (Line 14 thru 28)		106,849	203,319	
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			2,546,936	
34	Post-96 Carrying Charge Factor (Post-96 CCF)			7.7%	
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 2010

1	2009 Actual Annual RR			237,777	258,493	
2	2009 Est. Transmission Revenue Requirements (as billed)	6/09-05/10	Appendix C	106,849	203,319	ATRR - Prior Year
3	True-up (Over)/Under (Line 1 - Line 2)			130,928	55,174	

	(Overcollection)/Undercollection
Pre'97	$130,928
Post'96	$55,174

Initial Billing Period	Pre 1997 Balance	Post 1996 Balance	FERC Monthly Interest Rate	Pre 1997 Interest	Post 1996 Interest
June 2007	$130,928	$55,174	0.56%	$733	$309
July 2007	131,661	55,483	0.45%	592	$250
August 2007	131,661	55,483	0.45%	592	$250
September 2007	131,661	55,483	0.44%	579	$244
October 2007	133,425	56,226	0.42%	560	$236
November 2007	133,425	56,226	0.41%	547	$231
December 2007	133,425	56,226	0.42%	560	$236
January 2008	135,093	56,929	0.38%	513	$216
February 2008	135,093	56,929	0.34%	459	$194
March 2008	135,093	56,929	0.38%	513	$216
April 2008	136,579	57,555	0.28%	382	$161
May 2008	136,579	57,555	0.29%	396	$167
		Total Interest		$6,430	$2,710
		True-Up		$130,928	$55,174
		Total TU & Int		**$137,358**	**$57,884**

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: 26-May-11

Revenue Requirements for (year): Calendar Year 2010

Customer: Reading Municipal Light Department

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

		Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	=	2,354	(a)		(f)
Total of Attachment F - Section J - Support Revenue		0	(b)	0	(g)
Total of Attachment F - Section K - Support Expense		235,423	(c)		(h)
Total of Attachment F - Section (L through O)		0	(d)	0	(i)
Sub Total - Sum (A through I) - J + K + (L through O)		237,777	(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:	237,777	(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: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)	237,777	(l)=(k)+(b)+(g)-(h)

Calendar Year 2010

🟨 Shading denotes an input

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	Reading	Reference
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)	29,428	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		29,428	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	2,354	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)	235,423	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)		237,777	

Reading Municipal Light Department
Annual Revenue Requirements
Calendar Year 2010

🟨 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 = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

= (0.0000 +(0 + 0) / 29,428) x 0)
(1 - 0)

= 0.0000000

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)* State Income Tax Rate
(1 - State Income Tax Rate)

= (0.0000 +(0 + 0) / 29,428) + 0.0000000)* 0
(1 - 0)

= 0.0000000

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

		(PTF)	
INVESTMENT BASE	$	29,428	From Worksheet 1
x Cost of Capital Rate		0.0800000	
= Investment Return and Income Taxes		2,354	To Worksheet 1

Sheet: Worksheet 3a

Reading Municipal Light Department
Calendar Year 2010

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)
	Transmission Plant						
1	Transmission Plant	$ -		0		0	Line 1, Worksheet 5
2	General Plant	$ 21,921,026	0.0000% (a)	0	0.0000%	0	Page 8B line 29(g)
3	Total (line 1+2)			0		0	
4	Transmission Plant Held for Future Use	0		0	0.0000%	0	None known
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	1,791,005		1,791,005	0.0000%	0	Page 8A, line 31(g) less Page 16, line 31(g)
6	General Plant Accum.Depreciation	15,819,440	0.0000% (a)	0	0.0000%	0	Page 8B, line 29(g) less Page 17, line 29(g)
7	Total (line 5+6)			1,791,005		0	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	0	0.0772% (c)	0	0.0000%	0	None known
9	Accumulated Deferred Taxes (190)	0	0.0772% (c)	0	0.0000%	0	None known
10	Total (line 8+9)			0		0	
11	Transmission loss on Reacquired Debt	0	0.0772% (c)	0	0.0000%	0	None known
	Other Regulatory Assets						
12	FAS 106	0	0.0000% (a)	0	0.0000%	0	None known
13	FAS 109	0	0.0772% (c)	0	0.0000%	0	None known
14	Other Regulatory Liabilities (254.DK)	0	0.0772% (c)	0	0.0000%	0	
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments	0	0.0000% (a)	0	0.0000%	0	Assumed none
17	Transmission Materials and Supplies	0	0.0000%	0	0.0000%	0	Assumed none
18	Cash Working Capital						
19	Operation & Maintenance Expense					0	Worksheet 1, Line 20
20	Administrative & General Expense					0	Worksheet 1, Line 21
21	Transmission Support Expense					235,423	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					235,423	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					29,428	

(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

Sheet: Worksheet 4a

Calendar Year 2010

▨ 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	Transmission Depreciation	113,113		113,113	0.0000%	0	Page 16, line 31(d)
2	General Depreciation	793,192	0.0000% (a)	0	0.0000%	0	Page 17, line 29(d)
3	Total (line 1+2)			113,113		0	
4	Amortization of Loss on Reacquired Debt	0	0.0772% (c)	0	0.0000%	0	None known
5	Amortization of Investment Tax Credits	0	0.0772% (c)	0	0.0000%	0	None known
	Property Taxes *						
6	Transmission Property Taxes	2,179,275	0.0772%	1,682	0.0000%	0	DTE, p. 21 line 24
7	General Property Taxes	2,179,275	0.0000% (a)	0	0.0000%	0	DTE, p. 21 line 24
8	Total (line 6+7)			1,682		0	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	9,674,823		9,674,823	0	0	Page 40, line 50(b)
10	Transmission of Electricity by Others - #565	9,672,098		9,672,098	0	0	Page 40, line 38(b)
11	Load Dispatching - #561	0		0	0	0	Page 40, line 34(b)
12	**Station Expenses & Rents - #562 / #567	0		0	0	0	Page 40, line 35(b) 40(b)
13	O&M less lines 10, 11 & 12	2,725		2,725	0.0000%	0	
	Transmission Administrative and General						
14	Administrative and General	614,431					Page 42, line 6(b)
15	*less Property Insurance (#924)*	*368,703*					Page 41, line 47(b)
16	*less Regulatory Commission Expenses (#928)*	*0*					Page 41, line 50(b)
17	*less General Advertising Expense (#930.1)*	*154,140*					*assumed none*
18	Subtotal [line 14 minus (15 thru 17)]	91,588	0.0000% (a)	0	0.0000%	0	
19	***PLUS** Property Insurance alloc. using Plant Allocatior*	*368,703*	*0.0772% (c)*	285	0.0000%	0	
20	***PLUS** Regulatory Comm. Exp. (FERC Assessments)*	*0*	*0.0772% (c)*	0	0.0000%	0	
21	***PLUS** Trans. Related General Advertising Expense*	*0*	*0.0772% (c)*	0	0.0000%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*460,291*		*285*		*0*	
23	*Payroll Tax Expense*	69,571	*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

Sheet: Worksheet 5

▨ Shading denotes an input

Calendar Year 2010

Line No.		Reading	Mass DTE AR Reference
	PTF Transmission Plant Allocation Factor		
1	PTF Transmission Investment	0	See Worksheet
2	Total Transmission Investment	91,534	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	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	7,052,768	Page 42, line 24 (c)
8	Administrative and General Wages and Salaries	718,766	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)	6,334,002	
11	Percent Allocation (Line 6/Line 10)	0.0000%	
	Plant Allocation Factor		
12	Total Transmission Investment	91,534	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)*	91,534	
15	Total Plant in Service	118,620,901	Page 8B, line 30 (g)
16	Percent Allocation (Line 14 / Line 15)	0.0772%	

Sheet: Worksheet 6 of 7

Affiliated Company Wages and Salaries

Calendar Year 2010

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
Worksheet 7 of 7

Sheet: Worksheet 7

Calendar Year 2010

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.

			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]		1,825
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
	Schedue 125 Payments			139,620
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**			13,533
	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)		
NEP	**HQ Phase II - AC in MA**	332.1(g); [332(g) for CL&P]		32,789
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 394 line	332(g)		2,841
	115 kV Read - Washington V148 line			
NU	**345 kV 363, 369 and 394 Seabrook lines**			2,324
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310 line	330.1(n)		14,162
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
	Seabrook			28,329
		Total =	0	235,423

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: 26-May-11

Revenue Requirements for (year): Calendar Year 2010

Customer: Reading Municipal Light Department

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

		Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	=		(a)	258,493	(f)
Total of Attachment F - Section J - Support Revenue		0	(b)	0	(g)
Total of Attachment F - Section K - Support Expense		0	(c)		(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)	258,493	(j)

Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:	258,493	(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: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)	258,493	(l)=(k)+(b)+(g)-(h)

Calendar Year 2010

🟨 Shading denotes an input

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	Reading	Reference
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)	610,262	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)		2,028,208	
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)	1,141	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		2,029,349	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	162,348	Worksheet 2
15	Depreciation Expense	(B)	38,542	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)	48,474	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	0	*Worksheet 4, line 17 column 5*
20	Operation & Maintenance Expense	(G)	928	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	8,201	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)		258,493	

Reading Municipal Light Department
Annual Revenue Requirements
Calendar Year 2010

▨ 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

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

$$= \frac{(0.0000 + (0 + 0) / 2{,}029{,}349) \times 0)}{(1 - 0)}$$

$$= 0.0000000$$

(c) State Income Tax

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

$$= \frac{(0.0000 + (0 + 0) / 2{,}029{,}349) + 0.0000000)^{*}\ 0}{(1 - 0)}$$

$$= 0.0000000$$

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

		(PTF)	
INVESTMENT BASE	$	2,029,349	From Worksheet 1
x Cost of Capital Rate		0.0800000	
= Investment Return and Income Taxes		162,348	To Worksheet 1

Sheet: Worksheet 3a

Reading Municipal Light Department

Calendar Year 2010

🟨 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)
	Transmission Plant						
1	Transmission Plant	$ 2,638,470		2,638,470		2,638,470	Line 1, Worksheet 5
2	General Plant	$ 21,921,026	0.0000% (a)	0	34.0737%	0	Page 8B line 29(g)
3	Total (line 1+2)			2,638,470		2,638,470	
4	Transmission Plant Held for Future Use	0		0	34.0737%	0	None known
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	1,791,005		1,791,005	34.0737%	610,262	Page 8A, line 31(g) less Page 16, line 31(g)
6	General Plant Accum.Depreciation	15,819,440	0.0000% (a)	0	34.0737%	0	Page 8B, line 29(g) less Page 17, line 29(g)
7	Total (line 5+6)			1,791,005		610,262	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	0	6.5279% (c)	0	34.0737%	0	None known
9	Accumulated Deferred Taxes (190)	0	6.5279% (c)	0	34.0737%	0	None known
10	Total (line 8+9)			0		0	
11	Transmission loss on Reacquired Debt	0	6.5279% (c)	0	34.0737%	0	None known
	Other Regulatory Assets						
12	FAS 106	0	0.0000% (a)	0	34.0737%	0	None known
13	FAS 109	0	6.5279% (c)	0	34.0737%	0	None known
14	Other Regulatory Liabilities (254.DK)	0	6.5279% (c)	0	34.0737%	0	
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments	0	0.0000% (a)	0	34.0737%	0	Assumed none
17	Transmission Materials and Supplies	0	0.0000%	0	34.0737%	0	Assumed none
18	Cash Working Capital						
19	Operation & Maintenance Expense					928	Worksheet 1, Line 20
20	Administrative & General Expense					8,201	Worksheet 1, Line 21
21	Transmission Support Expense					0	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					9,129	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					1,141	

(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 2010

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	Mass DTE AR Reference for col (1)
	Depreciation Expense						
1	Transmission Depreciation	113,113		113,113	34.0737%	38,542	Page 16, line 31(d)
2	General Depreciation	793,192	0.0000% (a)	0	34.0737%	0	Page 17, line 29(d)
3	Total (line 1+2)			113,113		38,542	
4	Amortization of Loss on Reacquired Debt	0	6.5279% (c)	0	34.0737%	0	None known
5	Amortization of Investment Tax Credits	0	6.5279% (c)	0	34.0737%	0	None known
	Property Taxes *						
6	Transmission Property Taxes	2,179,275	6.5279%	142,261	34.0737%	48,474	DTE, p. 21 line 24
7	General Property Taxes	2,179,275	0.0000% (a)	0	34.0737%	0	DTE, p. 21 line 24
8	Total (line 6+7)			142,261		48,474	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	9,674,823		9,674,823	0.340737	3,296,570	Page 40, line 50(b)
10	Transmission of Electricity by Others - #565	9,672,098		9,672,098	0.340737	3,295,642	Page 40, line 38(b)
11	Load Dispatching - #561	0		0	0.340737	0	Page 40, line 34(b)
12	**Station Expenses & Rents - #562 / #567	0		0	0.340737	0	Page 40, line 35(b) 40(b)
13	O&M less lines 10, 11 & 12	2,725		2,725	34.0737%	928	
	Transmission Administrative and General						
14	Administrative and General	614,431					Page 42, line 6(b)
15	*less Property Insurance (#924)*	*368,703*					Page 41, line 47(b)
16	*less Regulatory Commission Expenses (#928)*	*0*					Page 41, line 50(b)
17	*less General Advertising Expense (#930.1)*	*154,140*					*assumed none*
18	Subtotal [line 14 minus (15 thru 17)]	91,588	0.0000% (a)	0	34.0737%	0	
19	***PLUS** Property Insurance alloc. using Plant Allocatior*	*368,703*	*6.5279% (c)*	24,069	34.0737%	8,201	
20	***PLUS** Regulatory Comm. Exp. (FERC Assessments)*	*0*	*6.5279% (c)*	0	34.0737%	0	
21	***PLUS** Trans. Related General Advertising Expense*	*0*	*6.5279% (c)*	0	34.0737%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*460,291*		*24,069*		*8,201*	
23	*Payroll Tax Expense*	69,571	*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

PTF Revenue Requirements
Worksheet 5 of 8
Calendar Year 2010

Sheet: Worksheet 5

▨ Shading denotes an input

Line No.			Mass DTE AR Reference
	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	7,052,768	Page 42, line 24 (c)
8	Administrative and General Wages and Salaries	718,766	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)	6,334,002	
11	Percent Allocation (Line 6/Line 10)	0.0000%	
	Plant Allocation Factor		
12	Total Transmission Investment	7,743,423	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)*	7,743,423	
15	Total Plant in Service	118,620,901	Page 8B, line 30 (g)
16	Percent Allocation (Line 14 / Line 15)	6.5279%	

Sheet: Worksheet 6

Affiliated Company Wages and Salaries

Calendar Year 2010

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

Calendar Year 2010

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)	TOTAL 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: 5/26/2011

Revenue Requirements for (year): 2010

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	=	68,850	(a)	0	(f)
Total of Attachment F - Section J - Support Revenue		0	(b)	0	(g)
Total of Attachment F - Section K - Support Expense		208,089	(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)		276,939	(e)=(a)-(b)+(c)+(d)	0	(j)=(f)-(g)+(h)+(i)
Forecasted Incremental Transmission Revenue Requirements				0	(m)
Annual True-up		(7,588)		0	(n)
Interest Charge on Annual True-up		(373)		-	(o)
Total = (e) + (j) + (k) + (l) + (m) + (n) + (o)		268,978	(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:				268,978	(r) = (p)+(q)

RNS Rate

Taunton Municipal Light Plant
Annual Revenue Requirements of pre-1997 & post-1996 PTF
for costs in 2010 06/10-05/11

Line No.		Attachment F Reference Section:	Pre 1997	Post 1996	Reference
	I. INVESTMENT BASE				
1	Transmission Plant	I (A)(1)(a)	1,500,243	0	Worksheet 3, line 1 column 5
2	General Plant	I (A)(1)(b)	1,512	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)		1,501,755	0	
5	Accumulated Depreciation	I (A)(1)(d)	1,343,496	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)		158,259	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)	27,421	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)	14,854	0	Worksheet 2
15	Depreciation Expense	I (B)	26,874	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)	23,302	0	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	I (F)	132	0	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	I (G)	17,621	0	Worksheet 4, line 13 column 5
21	Administrative & General Expense	I (H)	4,199	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)	197,545	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 Ta	I (N)	0	0	Txm related Acct 456
28	Transmission Rents Received from Electric Propert	I (O)	0	0	Txm related Acct 454-rent
29	Total Revenue Requirements (Line 14 thru 28)		284,527	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 2010

1	2009 Actual Annual RR			276,939	0	Input Panel Subtotals
2	2009 Est. Transmission Revenue Requirements (as billed)	6/09-05/10	Appendix C	284,527	0	ATRR - Prior Year
3	True-up (Over)/Under (Line 1 - Line 2)			-7,588	0	

	(Overcollection)/Undercollection
Pre'97	($7,588)
Post'96	$0

Initial Billing Period	Pre 1997 Balance	Post 1996 Balance	FERC Monthly Interest Rate	Pre 1997 Interest	Post 1996 Interest
June 2007	($7,588)	$0	0.56%	($42)	$0
July 2007	(7,630)	0	0.45%	-34	$0
August 2007	(7,630)	0	0.45%	-34	$0
September 2007	(7,630)	0	0.44%	-34	$0
October 2007	(7,733)	0	0.42%	-32	$0
November 2007	(7,733)	0	0.41%	-32	$0
December 2007	(7,733)	0	0.42%	-32	$0
January 2008	(7,829)	0	0.38%	-30	$0
February 2008	(7,829)	0	0.34%	-27	$0
March 2008	(7,829)	0	0.38%	-30	$0
April 2008	(7,916)	0	0.28%	-22	$0
May 2008	(7,916)	0	0.29%	-23	$0
		Total Interest		-$373	$0
		True-Up		-$7,588	$0
		Total TU & Int		**-$7,961**	**$0**

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: 26-May-11

Revenue Requirements for (year): Calendar Year 2010

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	=	68,850	(a)	0	(f)
Total of Attachment F - Section J - Support Revenue		0	(b)	0	(g)
Total of Attachment F - Section K - Support Expense		208,089	(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)		276,939	(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:		276,939	(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)
Voting Share Total for Participant's R Value: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)	(p)	276,939	(l)=(k)+(b)+(g)-(h)

Calendar Year 2010

▨ Shading denotes an input

Line No.		Attachment F Reference *Section:*	**Taunton**	Reference
	I. INVESTMENT BASE			
1	Transmission Plant	(A)(1)(a)	1,500,243	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	1,178	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)		1,501,421	
5	Accumulated Depreciation	(A)(1)(d)	1,370,460	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)		130,961	
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)	26,812	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		157,773	
II.	REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	12,622	Worksheet 2
15	Depreciation Expense	(B)	27,125	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)	22,592	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	108	*Worksheet 4, line 17 column 5*
20	Operation & Maintenance Expense	(G)	2,252	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	4,151	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)	208,089	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)		276,939	
			68,850	

Taunton Municipal Lighting Plant
Annual Revenue Requirements
Calendar Year 2010

▨ 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

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

$$= \frac{(0.0000 + (0 + 0) / 157{,}773) \times 0)}{(1 - 0)}$$

$$= 0.0000000$$

(c) State Income Tax

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

$$= \frac{(0.0000 + (0 + 0) / 157{,}773) + 0.0000000)}{(1 - 0)} * 0$$

$$= 0.0000000$$

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

		(PTF)	
INVESTMENT BASE	$	157,773	From Worksheet 1
x Cost of Capital Rate		0.0800000	
= Investment Return and Income Taxes		12,622	To Worksheet 1

PTF Revenue Requirements
Worksheet 3a of 7

Taunton Municipal Lighting Plant

Calendar Year 2010

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	Mass DTE AR Reference for col (1)
	Transmission Plant						
1	Transmission Plant	$ 7,283,794		7,283,794		1,500,243	Line 1, Worksheet 5
2	General Plant	30,922,895	0.0185% (a)	5,721	20.5970%	1,178	Page 8B line 29(g)
3	Total (line 1+2)			7,289,515		1,501,421	
4	Transmission Plant Held for Future Use	0		0	20.5970%	0	None known
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	6,651,602		6,651,602	20.5970%	1,370,030	Page 8A, line 31(g) less Page 16, line 31(g)
6	General Plant Accum.Depreciation	11,276,992	0.0185% (a)	2,086	20.5970%	430	Page 8B, line 29(g) less Page 17, line 29(g)
7	Total (line 5+6)			6,653,688		1,370,460	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	0	3.7637% (c)	0	20.5970%	0	None known
9	Accumulated Deferred Taxes (190)	0	3.7637% (c)	0	20.5970%	0	None known
10	Total (line 8+9)			0		0	
11	Transmission loss on Reacquired Debt	0	3.7637% (c)	0	20.5970%	0	None known
	Other Regulatory Assets						
12	FAS 106	0	0.0185% (a)	0	20.5970%	0	None known
13	FAS 109	0	3.7637% (c)	0	20.5970%	0	None known
14	Other Regulatory Liabilities (254.DK)	0	3.7637% (c)	0	20.5970%	0	
15	Total (line 12+13+14)			0		0	
16	Transmission Prepayments	0.00	0.0185% (a)	0	20.5970%	0	
17	Transmission Materials and Supplies	0.00	3.7637%	0	20.5970%	0	
18	Cash Working Capital						
19	Operation & Maintenance Expense					2,252	Worksheet 1, Line 20
20	Administrative & General Expense					4,151	Worksheet 1, Line 21
21	Transmission Support Expense					208,089	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					214,492	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					26,812	

(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 2010

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	Mass DTE AR Reference for col (1)
	Depreciation Expense						
1	Transmission Depreciation	131,376		131,376	20.5970%	27,060	Page 16, line 31(d)
2	General Depreciation	1,711,064	0.0185% (a)	317	20.5970%	65	Page 17, line 29(d)
3	Total (line 1+2)			131,693		27,125	
4	Amortization of Loss on Reacquired Debt	0	3.7637% (c)	0	20.5970%	0	None known
5	Amortization of Investment Tax Credits	0	3.7637% (c)	0	20.5970%	0	None known
	Property Taxes *						
6	Transmission Property Taxes	2,900,000	0.037637	109,147	20.5970%	22,481	
7	General Property Taxes	2,900,000	0.0185% (a)	537	20.5970%	111	
8	Total (line 6+7)			109,684		22,592	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	7,305,889		7,305,889	0.20597	1,504,794	Page 40, line 49(b)
10	Transmission of Electricity by Others - #565	7,281,529		7,281,529	0.20597	1,499,777	Page 40, line 38(b)
11	Load Dispatching - #561	10,951		10,951	0.20597	2,256	Page 40, line 34(b)
12	**Station Expenses & Rents - #562 / #567	2,470		2,470	0.20597	509	Page 40, line 35(b) 40(b)
13	O&M less lines 10, 11 & 12	10,939		10,939	20.5970%	2,252	
	Transmission Administrative and General						
14	Administrative and General	5,404,271					Page 42, line 5(b)
15	*less Property Insurance (#924)*	511,899					Page 41, line 47(b)
16	*less Regulatory Commission Expenses (#928)*	0					Page 41, line 50(b)
17	*less General Advertising Expense (#930.1)*	97,963					*930.1*
18	Subtotal [line 14 minus (15 thru 17)]	4,794,409	0.0185% (a)	887	20.5970%	183	
19	***PLUS*** *Property Insurance alloc. using Plant Allocatior*	*511,899*	*3.7637% (c)*	19,266	20.5970%	3,968	
20	***PLUS*** *Regulatory Comm. Exp. (FERC Assessments)*	*0*	*3.7637% (c)*	0	20.5970%	0	assumed none
21	***PLUS*** *Trans. Related General Advertising Expense*	*0*	*3.7637% (c)*	0	20.5970%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*5,306,308*		*20,153*		*4,151*	
23	*Payroll Tax Expense*	*2,827,711*	*0.0185% (a)*	*523*	*20.5970%*	*108*	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	1,941,987	|Combined
Medicare	160,303	
CT Unemployment		
MA Unemployment	725,421	
MA Universal Health		
VT Unemployment		
NH Unemployment		
Total	2,827,711	*To Line 23*

Calendar Year 2010

▨ Shading denotes an input

Line No.			Mass DTE AR Reference
	PTF Transmission Plant Allocation Factor	**Taunton**	
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%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	2,470	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)	2,470	
7	Total Wages and Salaries	15,240,807	Page 42, line 24©
8	Administrative and General Wages and Salaries	1,921,831	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)	13,318,976	
11	Percent Allocation (Line 6/Line 10)	0.0185%	
	Plant Allocation Factor		
12	Total Transmission Investment	7,283,794	Line 2
13	*plus Transmission-Related General Plant* *(Line 2 of Wkst. 3)*	5,721	*Worksheet 3, Line 2*
14	*= Revised Numerator* *(Line 12 + Line 13)*	7,289,515	
15	Total Plant in Service	193,678,895	Page 8B, line 29(g)
16	Percent Allocation (Line 14 / Line 15)	3.7637%	

Sheet: Worksheet 6 of 7

Affiliated Company Wages and Salaries

🟨 Shading denotes an input

Calendar Year 2010

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

Calendar Year 2010

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.

			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]		1,393
	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**			10,332
	Comerford 115 kV Substation			
	NEH HQ - II			68,395
	NHH-HQ-II			94,282
	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]		25,033
	345 kV Golden Hills-Mystic 349 line			
	HQ-1	332(g)		3,812
	115 kV Read - Washington V148 line			
NU	**345 kV 363, 369 and 394 Seabrook lines**			367
	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			4,475
		Total =	0	208,089

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: 5/31/2011

Revenue Requirements for (year): 2011

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

		Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	=	21,253,741	(a)	71,775,454	(f)
Total of Attachment F - Section J - Support Revenue		0	(b)	0	(g)
Total of Attachment F - Section K - Support Expense		780,134	(c)	0	(h)
Total of Attachment F - Section L through O		(98,687)	(d)	0	(i)
Sub Total - Sum (A through I) - J + K + (L through O)		21,935,188	(e)=(a)-(b)+(c)+(d)	71,775,454	(j)=(f)-(g)+(h)+(i)
Forecasted Incremental Transmission Revenue Requirements		0	n/a	(1,742,480)	(m)
Annual True-up		(1,024,135)	(k)	(5,343,554)	(n)
Interest Charge on Annual True-up		(34,128)	(l)	(178,065)	(o)
Total = (e) + (j) + (k) + (l) + (m) + (n) + (o)		20,876,926	(p)	64,511,355	(q)
Annual Projected 2011 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:				85,388,281	(r) = (p)+(q)

RNS Rate

The United Illuminating Company
Annual Revenue Requirements of pre-1997 PTF
for costs in 2010

Sheet: Worksheet 1

Worksheet 1of 8

🟨 Shading denotes an input

Line No.		Attachment F Reference	UI	Reference
	I. INVESTMENT BASE	*Section:*		
1	Transmission Plant	I (A)(1)(a)	110,399,304	Worksheet 3, line 1 column 5
2	General Plant	I (A)(1)(b)	2,396,992	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	I (A)(1)(c)	6,440,734	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		119,237,030	
5	Accumulated Depreciation	I (A)(1)(d)	18,825,578	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	I (A)(1)(e)	18,117,705	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	I (A)(1)(f)	973,713	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	I (A)(1)(g)	7,264,426	Worksheet 3, line 15 column 5
9	Net Investment (Line 4-5-6+7+8)		90,531,886	
10	Prepayments	I (A)(1)(h)	87,112	Worksheet 3, line 16 column 5
11	Materials & Supplies	I (A)(1)(i)	45,915	Worksheet 3, line 17 column 5
12	Cash Working Capital	I (A)(1)(j)	701,410	Worksheet 3, line 24 column 5
13	Total Investment Base (Line 9+11+12+13)		91,366,323	
	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	I (A)	11,504,418	Worksheet 2
15	Depreciation Expense	I (B)	2,671,837	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	I (C)	63,615	Worksheet 4, line 4 column 5
17	Investment Tax Credit	I (D)	(11,300)	Worksheet 4, line 5 column 5
18	Property Taxes	I (E)	2,068,063	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	I (F)	125,964	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	I (G)	2,103,450	Worksheet 4, line 13 column 5
21	Administrative & General Expense	I (H)	2,727,694	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)	780,134	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)	(41,372)	Txm related Acct 456
28	Transmission Rents Received from Electric Property	I (O)	(57,315)	Txm related Acct 454-rent
29	Total Revenue Requirements (Line 14 thru 28)		21,935,188	

The United Illuminating Company
Annual Revenue Requirements of post-1996 PTF
for costs in 2010

RNS Rate

Sheet: Worksheet 1a

Worksheet 1a of 8

🟨 Shading denotes an input

Line No.		Attachment F Reference	UI	Reference
	I. INVESTMENT BASE	*Section:*		
1	Transmission Plant	I (A)(1)(a)	357,244,350	Worksheet 3a, line 1 column 5
2	General Plant	I (A)(1)(b)	7,756,497	Worksheet 3a, line 2 column 5
3	Plant Held For Future Use	I (A)(1)(c)	20,841,762	Worksheet 3a, line 4 column 5
4	Total Plant (Lines 1+2+3)		385,842,609	
5	Accumulated Depreciation	I (A)(1)(d)	60,918,239	Worksheet 3a, line 7 column 5
6	Accumulated Deferred Income Taxes	I (A)(1)(e)	58,627,614	Worksheet 3a, line 10 column 5
7	Loss On Reacquired Debt	I (A)(1)(f)	3,150,866	Worksheet 3a, line 11 column 5
8	Other Regulatory Assets	I (A)(1)(g)	23,507,170	Worksheet 3a, line 15 column 5
9	Net Investment (Line 4-5-6+7+8)		292,954,792	
10	Prepayments	I (A)(1)(h)	281,887	Worksheet 3a, line 16 column 5
11	Materials & Supplies	I (A)(1)(i)	148,576	Worksheet 3a, line 17 column 5
12	Cash Working Capital	I (A)(1)(j)	1,954,155	Worksheet 3a, line 24 column 5
13	Total Investment Base (Line 9+11+12+13)		295,339,410	
	II. PRIOR CALENDAR YEAR ACTUAL REVENUE REQUIREMENT			
14	Investment Return and Income Taxes	I (A)	37,187,957	Worksheet 2a
15	Depreciation Expense	I (B)	8,645,876	Worksheet 4a, line 3 column 5
16	Amortization of Loss on Reacquired Debt	I (C)	205,854	Worksheet 4a, line 4 column 5
17	Investment Tax Credit	I (D)	(36,566)	Worksheet 4a, line 5 column 5
18	Property Taxes	I (E)	6,692,106	Worksheet 4a, line 8 column 5
19	Payroll Tax Expense	I (F)	407,610	Worksheet 4a, line 23 column 5
20	Operation & Maintenance Expense	I (G)	6,806,614	Worksheet 4a, line 13 column 5
21	Administrative & General Expense	I (H)	8,826,623	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)		68,736,074	0.192406329
	III. CURRENT CALENDAR YEAR ESTIMATED INCREMENTAL REVENUE REQUIREMENT			
30	Carrying Charge Factor Base Revenue Requirement Numerator		68,736,074	Sum of Lines 14 through 21
31	Post-2003 Enhanced Return Addition to Revenue Requirement		3,039,380	Worksheet 1b Line 6 Column 2 and L
32	Total Post-96 PTF Revenue Requirement		71,775,454	Line 30 + Line 31
33	Post-96 PTF Transmission Plant in Service		357,244,350	Line 1
34	Post-96 Carrying Charge Factor (Post-96 CCF)		0.200914176	Line 32 / Line 33
35	Forecasted Post-96 PTF Plant Additions		16,300,000	RSP July 2011 Update
36	Forecasted Post-96 Localized PTF Plant Additions		(24,972,760)	Tranfer of MN Localized
37	Forecasted Post-96 Pool-Supported PTF Plant Additions		(8,672,760)	Line 35 - Line 36
38	Post-96 Estimated Incremental Revenue Requirement		(1,742,480)	Line 34 * Line 37

The United Illuminating Company
Annual Revenue Requirements of post-2003 PTF Incremental Return
for costs in 2010

Line No.		(1) Total Transmission	(2) Post-2003 [1] PTF	(3) Post-2003 [2] PTF	Total Transmission Reference
I.	INVESTMENT BASE				
1	Transmission Plant	488,924,185	**334,872,885**	**186,513,308**	Internal Plant Accounting
2	Accumulated Depreciation	80,130,135	**19,290,180**	**10,744,003**	Internal Plant Accounting
3	Accumulated Deferred Income Taxes	80,237,682	**20,210,590**	**11,256,642**	Internal Plant Accounting
4	Other Regulatory Assets	32,171,886	0	0	Included on Line 3, above
5	Net Investment (Line 1-2-3+4)	360,728,254	295,372,115	164,512,663	
II.	ENHANCED RETURN ON POST-2003 TRANSMISSION PLANT				
6	Enhanced Return Addition to Revenue Requirement		2,377,332	662,048	Worksheet 2b
7	PTF Transmission Plant Allocation Factor		68.4918%		

Notes: 1. Incentive for New Trans Investment
Notes: 2. Incentive for used of Advanced Tech MN Proj

RNS Rate

The United Illuminating Company
Annual Revenue Requirements of PTF Facilities
for costs in 2010

Worksheet: 1 + 1a (Total pre-1997 and post-1996)

Worksheet 1c of 8

Line No.		Attachment F Reference	UI	Reference
	I. INVESTMENT BASE	*Section:*		
1	Transmission Plant	I (A)(1)(a)	467,643,653	Worksheet 1 + Worksheet 1a
2	General Plant	I (A)(1)(b)	10,153,489	Worksheet 1 + Worksheet 1a
3	Plant Held For Future Use	I (A)(1)(c)	27,282,496	Worksheet 1 + Worksheet 1a
4	Total Plant (Lines 1+2+3)		505,079,638	Worksheet 1 + Worksheet 1a
5	Accumulated Depreciation	I (A)(1)(d)	79,743,817	Worksheet 1 + Worksheet 1a
6	Accumulated Deferred Income Taxes	I (A)(1)(e)	76,745,319	Worksheet 1 + Worksheet 1a
7	Loss On Reacquired Debt	I (A)(1)(f)	4,124,579	Worksheet 1 + Worksheet 1a
8	Other Regulatory Assets	I (A)(1)(g)	30,771,596	Worksheet 1 + Worksheet 1a
9	Net Investment (Line 4-5-6+7+8)		383,486,677	Worksheet 1 + Worksheet 1a
10	Prepayments	I (A)(1)(h)	368,999	Worksheet 1 + Worksheet 1a
11	Materials & Supplies	I (A)(1)(i)	194,491	Worksheet 1 + Worksheet 1a
12	Cash Working Capital	I (A)(1)(j)	2,655,564	Worksheet 1 + Worksheet 1a
13	Total Investment Base (Line 9+11+12+13)		386,705,731	
	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	I (A)	48,692,375	Worksheet 1 + Worksheet 1a
15	Depreciation Expense	I (B)	11,317,713	Worksheet 1 + Worksheet 1a
16	Amortization of Loss on Reacquired Debt	I (C)	269,469	Worksheet 1 + Worksheet 1a
17	Investment Tax Credit	I (D)	(47,866)	Worksheet 1 + Worksheet 1a
18	Property Taxes	I (E)	8,760,169	Worksheet 1 + Worksheet 1a
19	Payroll Tax Expense	I (F)	533,574	Worksheet 1 + Worksheet 1a
20	Operation & Maintenance Expense	I (G)	8,910,064	Worksheet 1 + Worksheet 1a
21	Administrative & General Expense	I (H)	11,554,317	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)	780,134	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)	(41,372)	Worksheet 1 + Worksheet 1a
28	Transmission Rents Received from Electric Property	I (O)	(57,315)	Worksheet 1 + Worksheet 1a
29	Historic Revenue Requirements (Line 14 thru 28)		90,671,262	
	III. ENHANCED RETURN ON POST-2003 TRANSMISSION PLANT			
30	Enhanced Return Addition to Revenue Requirement		3,039,380	Worksheet 2b
	IV. CURRENT CALENDAR YEAR ESTIMATED INCREMENTAL REVENUE REQUIREMENT			
31	Post-96 Estimated Incremental Revenue Requirement		(1,742,480)	
	V. ANNUAL TRUE-UP			
32	Annual True-up		(6,579,881)	
	VI. TOTAL ESTIMATED REVENUE REQUIREMENT			
33	Total Estimated Revenue Requirement		85,388,281	

The United Illuminating Company
Annual Revenue Requirements of pre-1997 PTF
for costs in 2010

RNS Rate

Sheet: Worksheet 2

Worksheet 2 of 8

🟨 Shading denotes an input

		CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	516,490,374	51.93%	6.05%	3.14%	
PREFERRED STOCK			0.00%		0.00%	0.00%
COMMON EQUITY		478,099,216	48.07%	11.64%	5.60%	5.60%
TOTAL INVESTMENT RETURN	$	994,589,590	100.00%		8.74%	5.60%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0874

(b) Federal Income Tax = (R.O.E. + ((PTF Inv. Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

= (0.0560 + (((11,300) + 94,276) / 91,366,323) x 0.35)
(1 - 0.35)

= 0.0306429

(c) State Income Tax = (R.O.E. + ((PTF Inv. Tax Credit + Eq. AFUDC of Deprec. Exp.) / PTF Inv. Base) + Federal Income Tax)* State Income Tax Rate
(1 - State Income Tax Rate)

= (0.0560 + (((11,300) + 94,276) / 91,366,323) + 0.0306429)* 0.0825
(1 - 0.0825)

= 0.0078724

(a)+(b)+(c) **Cost of Capital Rate** = 0.1259153

	(pre-1997 PTF)	
INVESTMENT BASE	$ 91,366,323	From Worksheet 1
x Cost of Capital Rate	0.1259153	
= Investment Return and Income Taxes	$ 11,504,418	To Worksheet 1

The United Illuminating Company
Annual Revenue Requirements of post-1996 PTF
for costs in 2010

		CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	516,490,374	51.93%	6.05%	3.14%	
PREFERRED STOCK			0.00%		0.00%	0.00%
COMMON EQUITY		478,099,216	48.07%	11.64%	5.60%	5.60%
TOTAL INVESTMENT RETURN	$	994,589,590	100.00%		8.74%	5.60%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0874

(b) Federal Income Tax = (R.O.E. + ((PTF Inv. Tax Credit + Eq. AFUDC of Deprec. Exp) / PTF Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

= (0.0560 + (((36,566) + 305,071) / 295,339,410) x 0.35)
(1 - 0.35)

= 0.0306434

(c) State Income Tax = (R.O.E. + ((PTF Inv. Tax Credit + Eq. AFUDC of Deprec. Exp) / PTF Inv. Base) + Federal Income Tax)* State Income Tax Rate
(1 - State Income Tax Rate)

= (0.0560 + (((36,566) + 305,071) / 295,339,410) + 0.0306434)* 0.0825
(1 - 0.0825)

= 0.0078726

(a)+(b)+(c) **Cost of Capital Rate** = 0.1259160

		(post-1996 PTF)	
INVESTMENT BASE	$	295,339,410	From Worksheet 1a
x Cost of Capital Rate		0.1259160	
= Investment Return and Income Taxes	$	37,187,957	To Worksheet 1a

Sheet: Worksheet 2a

The United Illuminating Company
Annual Revenue Requirements of post-2003 PTF Incremental Return
for costs in 2010
Incremental Portion of ROE at 1% Adder

	CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 516,490,374	51.93%	#N/A		
PREFERRED STOCK					
COMMON EQUITY	478,099,216	48.07%	1.00%	0.48%	0.48%
TOTAL INVESTMENT RETURN	$ 994,589,590	100.00%		0.48%	0.48%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0048

(b) Federal Income Tax

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

$$= \frac{(0.0048 + ((0 + 0) / 295{,}372{,}115) \times 0.35)}{(1 - 0.35)}$$

$$= 0.0025846$$

(c) State Income Tax

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

$$= \frac{(0.0048 + ((0 + 0) / 295{,}372{,}115) + 0.0025846)^{*}\ 0.0825}{(1 - 0.0825)}$$

$$= 0.0006640$$

(a)+(b)+(c) **Cost of Capital Rate** = 0.0080486

	(post-2003 PTF)	
INVESTMENT BASE	$ 295,372,115	From Worksheet 1b
x Cost of Capital Rate	0.0080486	
= Investment Return and Income Taxes	$ 2,377,332	To Worksheet 1b

The United Illuminating Company
Annual Revenue Requirements of post-2003 PTF Incremental Return
for costs in 2010
Incremental Portion of ROE at 1% Adder

		CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	516,490,374	51.93%	#N/A		
PREFERRED STOCK						
COMMON EQUITY		478,099,216	48.07%	0.50%	0.24%	0.24%
TOTAL INVESTMENT RETURN	$	994,589,590	100.00%		0.24%	0.24%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0024

(b) Federal Income Tax

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

$$= \frac{(\ 0.0024 + ((\ 0 + 0\ ) / \ 164{,}512{,}663\ ) \ \text{x} \ 0.35\ )}{(\ 1 - 0.35\ )}$$

$$= 0.0012923$$

(c) State Income Tax

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

$$= \frac{(\ 0.0024 + ((\ 0 + 0\ ) / \ 164{,}512{,}663\ ) + 0.0012923\ )^{*} \ 0.0825}{(\ 1 - 0.0825\ )}$$

$$= 0.0003320$$

(a)+(b)+(c) **Cost of Capital Rate** = 0.0040243

	(post-2003 PTF)	
INVESTMENT BASE	$ 164,512,663	From Worksheet 1b
x Cost of Capital Rate	0.0040243	
= Investment Return and Income Taxes	$ 662,048	To Worksheet 1b

The United Illuminating Company - 2010

Sheet: Worksheet 3

Pre-1997 PTF

RNS Rate
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)
	Transmission Plant						
1	Transmission Plant	**488,924,185**		488,924,185		110,399,304 (c)	Internal Company Record
2	General Plant	**101,158,997**	10.4939% (a)	10,615,532	22.5800%	2,396,992	Page 207.96g
3	Total (line 1+2)			499,539,717		112,796,296	
4	Transmission Plant Held for Future Use	**28,524,010**		28,524,010	22.5800%	6,440,734	Page 214.47d
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	**80,130,135**		80,130,135	22.5800%	18,093,421	Page 219.25b
5A	Transmission Cost of Removal			0	22.5800%	0	Included in Page 269.12f
6	General Plant Accum.Depreciation	30,898,824	10.4939% (a)	3,242,494	22.5800%	732,157	Page 219.28b
7	Total (line 5+6)			83,372,629		18,825,578	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	**(363,925,189)**	34.1607%	(124,319,350)	22.5800%	(28,071,366)	Internal Company Record
9	Accumulated Deferred Taxes (190)	**129,042,096**	34.1607%	44,081,668	22.5800%	9,953,661	Internal Company Record
10	Total (line 8+9)			(80,237,682)		(18,117,705)	
11	Transmission loss on Reacquired Debt	**12,623,493**	34.1607%	4,312,272	22.5800%	973,713	Page 123.1 footnote
	Other Regulatory Assets/Liabilities						
12	FAS 106	0	10.4939% (a)	0	22.5800%	0	Page 232
13	FAS 109 Asset	**96,898,373**	34.1607%	33,101,151	22.5800%	7,474,255	Internal Company Record
14	FAS 109 Liability	**(2,720,278)**	34.1607% (d)	(929,266)	22.5800%	(209,829)	Internal Company Record
15	Total (line 12+13+14)	94,178,095		32,171,886		7,264,426	
16	Transmission Prepayments	**3,676,329**	10.4939% (a)	385,791	22.5800%	87,112	Page 111.57c
17	Transmission Materials and Supplies	**203,342**		203,342	22.5800%	45,915	Page 227.8c
18	Cash Working Capital						
19	Operation & Maintenance Expense					2,103,450	Worksheet 1, Line 20
20	Administrative & General Expense					2,727,694	Worksheet 1, Line 21
21	Transmission Support Expense					780,134	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					5,611,278	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					701,410	

(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 - 2010

Sheet: Worksheet 3a

post-1996 PTF

RNS Rate
Worksheet 3a 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)
	Transmission Plant						
1	Transmission Plant	488,924,185		488,924,185		357,244,350 (c)	Internal Company Records
2	General Plant	101,158,997	10.4939% (a)	10,615,532	73.0674%	7,756,497	Page 207.96g
3	Total (line 1+2)			499,539,717		365,000,847	
4	Transmission Plant Held for Future Use	28,524,010		28,524,010	73.0674%	20,841,762	Page 214.47d
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	80,130,135		80,130,135	73.0674%	58,549,032	Page 219.25b
5A	Transmission Cost of Removal	0		0	73.0674%	0	Included in Page 269.12f
6	General Plant Accum.Depreciation	30,898,824	10.4939% (a)	3,242,494	73.0674%	2,369,207	Page 219.28b
7	Total (line 5+6)			83,372,629		60,918,239	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	(363,925,189)	34.1607%	(124,319,350)	73.0674%	(90,836,957)	Internal Company Records
9	Accumulated Deferred Taxes (190)	129,042,096	34.1607%	44,081,668	73.0674%	32,209,343	Internal Company Records
10	Total (line 8+9)			(80,237,682)		(58,627,614)	
11	Transmission loss on Reacquired Debt	12,623,493	34.1607%	4,312,272	73.0674%	3,150,866	Page 123.1 footnote
	Other Regulatory Assets						
12	FAS 106	0	10.4939% (a)	0	73.0674%	0	Page 232
13	FAS 109 Asset	96,898,373	34.1607%	33,101,151	73.0674%	24,186,161	Internal Company Records
14	FAS 109 Liability	(2,720,278)	34.1607% (d)	(929,266)	73.0674%	(678,991)	Page 278.3f
15	Total (line 12+13+14)	94,178,095		32,171,886		23,507,170	
16	Transmission Prepayments	3,676,329	10.4939% (a)	385,791	73.0674%	281,887	Page 111.57c
17	Transmission Materials and Supplies	203,342		203,342	73.0674%	148,576	Page 227.8c
18	Cash Working Capital						
19	Operation & Maintenance Expense					6,806,614	Worksheet 1a, Line 20
20	Administrative & General Expense					8,826,623	Worksheet 1a, Line 21
21	Transmission Support Expense					0	Worksheet 1a, Line 24
22	Subtotal (line 19+20+21)					15,633,237	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					1,954,155	

(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 - 2010

pre-1997 PTF

Sheet: Worksheet 4

RNS Rate
Worksheet 4 of 8

▨ 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	Transmission Depreciation	**11,215,035**		11,215,035	22.5800%	2,532,360	Page 336.7f
2	General Depreciation	**5,886,272**	10.4939% (a)	617,700	22.5800%	139,477	Page 336.10f
3	Total (line 1+2)			11,832,735		2,671,837	
4	Amortization of Loss on Reacquired Debt	**824,725**	34.1607% (c)	281,732	22.5800%	63,615	Page 117.64c
5	Amortization of Investment Tax Credits	**146,496**	34.1607% (c)	50,044	22.5800%	11,300	Page 266.8f
	Property Taxes						
6	Transmission Property Taxes	**9,158,808**		9,158,808	22.5800%	2,068,063	Page 262.28a
7	General Property Taxes (included above)					0	Page 263.13i
8	Total (line 6+7)			9,158,808		2,068,063	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	**83,090,967**					Page 321.112b
10	Transmission of Electricity by Others - #565	**72,168,542**					Page 321.96b
11	Load Dispatching - #561	**1,606,901**					Page 321.84b
12	**Station Expenses & Rents - #562 / #567	0					Worksheet 7
13	O&M less lines 10, 11 & 12	9,315,524		9,315,524	22.5800%	2,103,450	
	Transmission Administrative and General						
14	Administrative and General	**104,365,725**					Page 323.197b
15	less Property Insurance (#924)	**237,720**					Page 323.185b
16	less Regulatory Expenses (#928)	**2,605,518**					Page 323.189b
17	less General Advertising Expense (#930.1)	**(792)**					Page 323.191b
18	Subtotal [Line 14 minus (15 thru 17)]	101,523,279	10.4939% (a)	10,653,759	22.5800%	2,405,624	
19	Plus Property Insurance (#924)	237,720	34.1607% (c)	81,207	22.5800%	18,337	Page 323.185b
20	Plus FERC Assessments (#928)	**614,900**	100.0000%	614,900	22.5800%	138,845	Page 351.3d plus footn
20A	Plus CT Regulatory Expenses (#928)	**2,137,655**	34.1607% (c)	730,238	22.5800%	164,888	Page 351.1d + 351.5d
21	Plus Trans. Related General Advertising Exp.	0		0	22.5800%	0	
22	Total Transmisson A&G [line 18 plus (19 thru 21)]			12,080,104		2,727,694	
23	Payroll Tax Expense	5,315,986 (e)	10.4939% (a)	557,855	22.5800%	125,964	

(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	Federal Unemployment	**47,356**	Page 263.5i
25	FICA	**5,027,472**	Page 263.4i
26 ***	Medicare	**0**	
27	CT State Unemployment	**241,158**	Page 263.12i
	Total	5,315,986	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

RNS Rate

The United Illuminating Company - 2010

Sheet: Worksheet 4a

post-1996 PTF

Worksheet 4a 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)
	Depreciation Expense						
1	Transmission Depreciation	11,215,035		11,215,035	73.0674%	8,194,538	Page 336.7f
2	General Depreciation	5,886,272	10.4939% (a)	617,700	73.0674%	451,338	Page 336.10f
3	Total (line 1+2)			11,832,735		8,645,876	
4	Amortization of Loss on Reacquired Debt	824,725	34.1607% (c)	281,732	73.0674%	205,854	Page 117.64c
5	Amortization of Investment Tax Credits	146,496	34.1607% (c)	50,044	73.0674%	36,566	Page 266.8f
	Property Taxes						
6	Transmission Property Taxes	9,158,808		9,158,808	73.0674%	6,692,106	Page 262.28a
7	General Property Taxes	0	0.0000% 0	0	73.0674%	0	Page 263.13i
8	Total (line 6+7)			9,158,808		6,692,106	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	83,090,967					Page 321.112b
10	Transmission of Electricity by Others - #565	72,168,542					Page 321.96b
11	Load Dispatching - #561	1,606,901					Page 321.84b
12	**Station Expenses & Rents - #562 / #567	0					Worksheet 7
13	O&M less lines 10, 11 & 12	9,315,524		9,315,524	73.0674%	6,806,614	
	Transmission Administrative and General						
14	Administrative and General	104,365,725					Page 323.197b
15	less Property Insurance (#924)	237,720					Page 323.185b
16	less Regulatory Expenses (#928)	2,605,518					Page 323.189b
17	less General Advertising Expense (#930.1)	(792)					Page 323.191b
18	Subtotal [Line 14 minus (15 thru 17)]	101,523,279	10.4939% (a)	10,653,759	73.0674%	7,784,429	
19	Plus Property Insurance (#924)	237,720	34.1607% (c)	81,207	73.0674%	59,336	Page 323.185b
20	Plus FERC Assessments (#928)	614,900	100.0000%	614,900	73.0674%	449,292	Page 351.3d plus footnote
20A	Plus CT Regulatory Expenses (#928)	2,137,655	34.1607% (c)	730,238	73.0674%	533,566	Page 351.1d + 351.5d
21	Plus Trans. Related General Advertising Exp.	0		0	73.0674%	0	
22	Total Transmisson A&G [line 18 plus (19 thru 21)]			12,080,104		8,826,623	
23	Payroll Tax Expense	5,315,986 (e)	10.4939% (a)	557,855	73.0674%	407,610	

(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	Federal Unemployment	47,356	Page 263.5i
25	FICA	5,027,472	Page 263.4i
26 ***	Medicare	0	
27	CT State Unemployment	241,158	Page 263.12i
	Total	5,315,986	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 - 2010

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	**110,399,304**	Internal Plant Accounting
2	Total Transmission Investment	488,924,185	Internal Company Records
3	Percent Allocation (line 1/2)	22.5800%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	**5,008,137**	Page 354.21b
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 of 8
6	Total Transmission Wages and Salaries (line 4+ 5)	5,008,137	
7	Total Wages and Salaries	**74,475,137**	Page 354.28b
8	Administrative and General Wages and Salaries	**26,750,901**	Page 354.27b
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)	47,724,236	
11	Percent Allocation (line 6/10)	10.4939%	
	Plant Allocation Factor		
12	Total Transmission Investment	488,924,185	Internal Company Records
13	plus Transmission-related General Plant	10,615,532	Worksheet 3 of 8, Line 2
14	Total Transmission Related Plant (line 12 + line 13)	499,539,717	
15	Total Plant in Service	**1,462,323,330**	Page 207.104g
16	Percent Allocation (line 14/15)	34.1607%	

The United Illuminating Company - 2010

post-1996 PTF

Sheet: Worksheet 5a

RNS Rate
Worksheet 5a of 8

🟨 Shading denotes an input

Line No.			FERC Form 1 Reference
	PTF Transmission Plant Allocation Factor		
1	PTF Transmission Investment	**357,244,350**	Internal Plant Accounting
2	Total Transmission Investment	488,924,185	Internal Company Records
3	Percent Allocation (line 1/2)	73.0674%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	5,008,137	Page 354.21b
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 of 8
6	Total Transmission Wages and Salaries (line 4+ 5)	5,008,137	
7	Total Wages and Salaries	74,475,137	Page 354.28b
8	Administrative and General Wages and Salaries	26,750,901	Page 354.27b
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)	47,724,236	
11	Percent Allocation (line 6/10)	10.4939%	
	Plant Allocation Factor		
12	Total Transmission Investment	488,924,185	Internal Company Records
13	plus Transmission-related General Plant	10,615,532	Worksheet 3 of 8, Line 2
14	Total Transmission Related Plant (line 12 + line 13)	499,539,717	
15	Total Plant in Service	1,462,323,330	Page 207.104g
16	Percent Allocation (line 14/15)	34.1607%	

The United Illuminating Company - 2010

RNS Rate

Sheet: Worksheet 6

Worksheet 6 of 8

Affiliated Company Wages and Salaries-2010

▨ Shading denotes an input

Line		UI	
"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 - 2010

Sheet: Worksheet 7

For the Year 2011

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 - 2010		
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		25,231	Page 332.11g
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
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		161,982	Page 332.10g
	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		378,126	Page 332.9g
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 394 line			
	115 kV Read - Washington V148 line			
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		214,795	Page 332.2g
	Substation Supply Agreements			
	Total =	0	780,134	

Summary of The United Illuminating Company System
Monthly Coincident Peaks for 2010
(Kilowatts)

🟨 Shading denotes an input

	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Day	5	1	3	7	26	28	6	31	1	1	29	15
Hour	1,800	1,900	1,900	2,100	1,700	1,500	1,500	1,700	1,600	1,100	1,800	1,800
The UI Co.	665,367	644,664	607,874	567,765	791,887	918,465	1,014,832	932,334	945,148	602,114	613,302	685,538
Hosley Substation	3,399	2,302	2,188	3,426	1,484	3,783	3,685	2,947	1,163	2,534	3,518	3,676
PSEG/Wisvest-Connecticut, (kW)	4,752	4,752	6,192	6,480	0	0	0	0	0	5,472	7,344	0
FPL Energy / Brigdeport Energy	0	3,000	0	0	0	0	0	0	0	0	0	3,450

Annual UI System Average 12 CP Load **755,403**

The United Illuminating Company - 2010

	YEAR	Equity AFUDC	DEBT AFUDC	Total AFUDC	AFUDC RATE	RNS 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%
1	1970	0.00	1.00	1.00	0.00%	0.00%
2	1971	0.00	1.00	1.00	0.00%	0.00%
3	1972	0.00	1.00	1.00	0.00%	0.00%
4	1973	0.00	1.00	1.00	0.00%	0.00%
5	1974	0.00	1.00	1.00	0.00%	0.00%
6	1975	0.00	1.00	1.00	0.00%	0.00%
7	1976	0.00	1.00	1.00	0.00%	0.00%
8	1977	2,518,016.00	2,419,271.00	4,937,287.00	8.30%	4.23%
9	1978	3,396,839.00	4,871,127.00	8,267,966.00	8.30%	3.41%
10	1979	4,574,700.00	10,925,831.00	15,500,531.00	9.90%	2.92%
11	1980	13,007.00	14,548.00	27,555.00	11.00%	5.19%
12	1981	21,022.00	7,091.00	28,113.00	9.00%	6.73%
13	1982	31,631.00	8,718.00	40,349.00	10.00%	7.84%
14	1983	40,443.00	11,964.00	52,407.00	10.25%	7.91%
15	1984	44,495.00	12,747.00	57,242.00	10.50%	8.16%
16	1985	46,083.00	16,540.00	62,623.00	10.75%	7.91%
17	1986	57,393.00	20,651.00	78,044.00	11.00%	8.09%
18	1987	54,933.00	26,486.00	81,419.00	13.00%	6.80%
19	1988	48,605.00	27,051.00	75,656.00	10.00%	6.58%
20	1989	38,968.00	26,475.00	65,443.00	12.30%	5.57%
21	1990	1,085.00	2,358.00	3,443.00	11.75%	3.39%
22	1991	1,259.00	3,931.00	5,190.00	10.88%	2.06%
23	1992	1,003.00	2,229.00	3,232.00	10.25%	3.18%
24	1993	999.00	3,068.00	4,067.00	8.75%	2.15%
25	1994	753.00	2,710.00	3,463.00	8.19%	1.78%
26	1995	390.00	2,372.00	2,762.00	8.00%	1.13%
27	1996	940.00	1,435.00	2,375.00	9.00%	3.56%
28	1997	336.00	1,239.00	1,575.00	7.50%	1.60%
29	1998	13.00	455.00	468.00	7.00%	0.19%
30	1999	575.00	1,660.00	2,235.00	7.75%	1.99%
31	2000	1,149.00	1,459.00	2,608.00	8.42%	3.71%
32	2001	1,123.00	789.00	1,912.00	9.02%	5.41%
33	2002	1,237.00	983.00	2,220.00	9.09%	5.41%
34	2003				8.08%	5.02%
35	2004					5.02%
36	2005					5.21%
37	2006					3.69%
38	2007					3.80%
39	2008					5.02%
40	2009					1.92%
41	2010					6.04%

Total	152.64%
Total divided by 41 years	3.72%
Transmission Depreciation	$11,215,035
Equity AFUDC Portion of Depr. Exp.	$417,519
PTF % Pre-97	22.5800%
Pre- 97 PTF Equity AFUDC Portion of Depr. Exp.	$94,276
PTF % Post-96	73.0674%
Post-96 PTF Equity AFUDC Portion of Depr. Exp.	$305,071

The United Illuminating Company
2011 Estimated Plant in service

		Transmission Total for 2011 Plant in Service	Less Localized Portion	2011 Estimated Plant in service
98-5073	East Shore 115 kV Capacitor Bank Transient Recovery	$4,800,000	-	4,800,000
98-5886	Water Street 115kV circuit breaker and switch replacements.	$3,000,000	-	3,000,000
98-6119	Devon Tie 115kV Switching Station BPS Compliance	$4,000,000	-	4,000,000
98-6123	West River 115kV Switching Station Fault Duty Mitigation	$3,500,000	-	3,500,000
various	Other	$1,000,000		1,000,000
	Total	$16,300,000	$ -	$ 16,300,000

The United Illuminating Company
PTF Investment By Year
As of 12/31/2010

Pre-97 PTF	**FERC#**								
Year	**3530**	**3540**	**3550**	**3560**	**3570**	**3580**	**3520**	**3500**	**Pre-97 PTF**
1923								4,789.83	4,789.83
1925		53,194.27		29,047.79					82,242.06
1926								166,207.11	166,207.11
1936								17,786.56	17,786.56
1937								20,596.27	20,596.27
1941	226.13						35.64		261.77
1942	17,480.41	229,476.46		9,590.14	185,294.38		405.89		442,247.28
1944								239.49	239.49
1947	(13,777.54)						13,845.36		67.82
1948	1.59								1.59
1949	1,570.54						626.98	315.36	2,512.88
1950						442.92			442.92
1952	138.31						722.46	7,758.19	8,618.96
1953		6,813.27					1,042.67	12,695.01	20,550.96
1954	122,560.77	64,630.55		3,548.97			5,619.09	748.96	197,108.34
1955	3,548.63	20,335.11		478.23			1,541.24	2,400.22	28,303.43
1956	152.47						366.18		518.65
1957	297.97						3,163.45		3,461.42
1958	503,489.82	36,281.88		3,843.89	53,354.69		45,028.54	21,460.49	663,459.31
1959	135,453.32	38,759.65		76,362.51			2,994.55	127,998.32	381,568.35
1960	183,052.44				258,527.81	271,620.69	9,154.68	25,587.14	747,942.76
1961	110,014.13	392,981.98		132,082.43	533,659.12	489,080.27	14,316.81	223,274.71	1,895,409.45
1962	78,925.97	264,510.32		201,744.96		329.55	1,471.69	105,000.93	651,983.42
1963	67,920.03	77,818.49		14,813.88	957.05		12,521.58	26,967.28	200,998.30
1964	109,763.88	763.19		1,441.57			8,670.90	866.78	121,506.32
1965	139,503.19			1,689.01			4,348.36	241.05	145,781.61
1966	767,610.98	758,669.73		631,547.86	529,545.19	488,886.62	56,421.97	15,936.94	3,248,619.29
1967	424.09	971.83					3,470.71	32,641.51	37,508.14
1968	311,159.02	109,517.30	213,067.23	136,209.24	3,829.12	5,113.27	208,542.91	223,040.31	1,210,478.40
1969	1,309,209.12		1,956.12	548.85	2,165.29	1,061,216.21	105,821.98	188,180.66	2,669,098.22
1970	101,023.23		1,573.96	6,529.20	60,559.12	85,538.57	13,305.03	3,298.32	271,827.43
1971	698,162.45			4,191.55		3,152.46	22,721.09	-	728,227.54
1972	257,773.03			60,000.00			10,528.64	(949.27)	327,352.39
1973	1,595,047.51	163,137.28	2,175,313.07	809,883.37			125,476.07	356,283.14	5,225,140.44
1974	4,708,876.45	2,354.29	2,716,632.00	733,053.93		59,635.26	279,514.68	(822.21)	8,499,244.41
1975	217,868.58		41,426.49	10,957.97			47,907.39	940,916.25	1,259,076.67
1976	63,222.77	15.39					706.45	2,078.65	66,023.27
1977	8,181.59	81,979.29		210,621.90				-	300,782.78
1978	619,584.32		4,742,480.25	406,040.48				1,725.13	5,769,830.18
1979	6,935.47			38,716.77					45,652.24
1980	2,247.49		118,029.43	59,419.37					179,696.29
1981	164,778.60		415,774.29	38,962.55	5,675.72		38,161.48	20,576.44	683,929.09
1982	80,926.39		112,048.03				13,442.71	-	206,417.13
1983	26,332.70		1,560.04	60,682.30				11,004.36	99,579.41
1984	45,436.70			7,276.18			3,259.91		55,972.79
1985	80,492.61					25,600.45		55,645.32	161,738.37
1986	93,395.89								93,395.89
1987	74,926.28								74,926.28
1988	22,659.38							5,002.01	27,661.39
1989	4,374,458.40	65,160.06		5,967,775.22		1,380,105.84	675,694.57		12,463,194.09
1990	1,498,127.97	3,463,931.03		648,391.20			4,258.83		5,614,709.03
1991	2,937,530.52				851,782.51	7,256,907.43			11,046,220.46
1992	4,576,098.12				65,673.56	690,674.29	1,185,354.55	1,488,728.23	8,006,528.75
1993	4,113,739.54					103,466.78	120,869.57		4,338,075.89
1994	3,066,437.89	1,306,048.20	8,919,373.29	2,886,757.08		108,766.34	76,248.99		16,363,631.78
1995	9,569,644.21	301,344.42	866,352.49	931,130.83	13,967.63	77,322.69	899,316.15	2,444,973.59	15,104,052.01
1996	185,699.26	38,736.22		105,736.31			77,844.88	8,090.01	416,106.67
Pre-97 PTF	**43,038,332.63**	**7,477,430.21**	**20,325,586.69**	**14,229,075.54**	**2,564,991.19**	**12,107,859.64**	**4,094,744.62**	**6,561,283.07**	**110,399,303.59**

The United Illuminating Company
PTF Investment By Year
As of 12/31/2010

PTF2	FERC#								
Year	3530	3540	3550	3560	3570	3580	3520	3500	Post-96 PTF
1997	731,953.65			5,944.10		96,292.33	1,337,557.17		2,171,747.25
1998	962,836.72	911,471.30		17,796.92			149,470.63		2,041,575.57
1999	-								-
2000	433,795.62	668,343.63		66,708.68			72,913.08		1,241,761.01
2001	866,265.02						66,417.69		932,682.71
2002	896,583.61	1,420,331.53		42,626.88					2,359,542.02
2003	1,093,706.89		-	-					1,093,706.89
2004	2,786,522.66			1,288,165.27		1,162,351.51	191,055.81		5,428,095.24
2005	1,491,415.12	193,047.80	-	136,371.32	398,079.45	748,951.86	7,249.40		2,975,114.95
2006	2,543,770.84	191,585.67	-	21.00	6,839.28		29,433.28	-	2,771,650.07
2007	903,726.94			490,620.70		-	133,101.26	2,791.47	1,530,240.37
2008	130,692,953.07			230,135.53	122,553,347.81	50,136,016.93	14,058,154.44	1,163,744.17	318,834,351.95
2009	2,404,905.37	886,014.40		4,927.35	255,698.68	114,546.33	2,549,898.23		6,215,990.36
2010	3,933,590.47			136,424.46	1,708,418.22	3,004,455.26	865,002.96		9,647,891.37
Post-96 PTF	**149,742,025.98**	**4,270,794.33**	**-**	**2,419,742.21**	**124,922,383.44**	**55,262,614.22**	**19,460,253.95**	**1,166,535.64**	**357,244,349.77**

RNS Rate

The United Illuminating Company
Annual Revenue Requirements of pre-1997 & post-1996 PTF
for costs in 2010 06/10-05/11

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	Pre 1997	Post 1996	Reference
1	Transmission Plant	I (A)(1)(a)	110,228,207	349,117,069	Worksheet 3, line 1 column 5
2	General Plant	I (A)(1)(b)	2,351,015	7,446,185	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	I (A)(1)(c)	6,230,425	19,733,133	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		118,809,647	376,296,387	
			0	0	
5	Accumulated Depreciation	I (A)(1)(d)	16,715,343	52,941,184	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	I (A)(1)(e)	13,693,285	43,369,658	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	I (A)(1)(f)	1,022,638	3,238,922	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	I (A)(1)(g)	7,039,173	22,294,617	Worksheet 3, line 15 column 5
9	Net Investment (Line 4-5-6+7+8)		96,462,830	305,519,084	
			0	0	
10	Prepayments	I (A)(1)(h)	94,751	300,099	Worksheet 3, line 16 column 5
11	Materials & Supplies	I (A)(1)(i)	48,088	152,305	Worksheet 3, line 17 column 5
12	Cash Working Capital	I (A)(1)(j)	749,890	2,047,460	Worksheet 3, line 24 column 5
			0	0	
13	Total Investment Base (Line 9+11+12+13)		97,355,559	308,018,948	
	II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	I (A)	12,765,855	40,389,508	Worksheet 2
15	Depreciation Expense	I (B)	2,663,093	8,434,602	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	I (C)	86,730	274,693	Worksheet 4, line 4 column 5
17	Investment Tax Credit	I (D)	(12,139)	(38,446)	Worksheet 4, line 5 column 5
18	Property Taxes	I (E)	1,404,201	4,447,416	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	I (F)	140,636	445,427	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	I (G)	2,429,509	7,694,792	Worksheet 4, line 13 column 5
21	Administrative & General Expense	I (H)	2,742,117	8,684,890	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)	827,492	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 Ta	I (N)	(15,343)	0	Txm related Acct 456
28	Transmission Rents Received from Electric Proper	I (O)	(72,828)	0	Txm related Acct 454-rent
			0	0	
29	Total Revenue Requirements (Line 14 thru 28)		22,959,323	70,332,882	
	III. <u>CURRENT CALENDAR YEAR ESTIMATED INCREMENTAL REVENUE REQUIREMENT</u>				
30	Carrying Charge Factor Base Revenue Requirement Numerator			70,332,882	
31	Post-2003 Enhanced Return Addition to Revenue Requirement			3,466,075	
32	Total Post-96 PTF Revenue Requirement			73,798,957	
				0	
33	Post-96 PTF Transmission Plant in Service			349,117,069	
34	Post-96 Carrying Charge Factor (Post-96 CCF)			0	
35	Forecasted Post-96 PTF Plant Additions			15,706,000	
36	Forecasted Post-96 Localized PTF Plant Additions			0	
37	Forecasted Post-96 Pool-Supported PTF Plant Additions			15,706,000	
38	Post-96 Estimated Incremental Revenue Requirement			3,320,051	incremental

The United Illuminating Company
FERC Interest Calculation associated with Under / (Over)
True-up and Interest Calculation for 2010

1	2010 Est. Transmission Revenue Requirements (as billed)	6/10-05/11	Appendix C	22,959,323	77,119,008	ATRR - Prior Year
2	2010 Actual Annual RR			21,935,188	71,775,454	Input Panel Subtotals
3	True-up Over/(Under) (Line 1 - Line 2)			1,024,135	5,343,554	

	Undercollection / (Overcollection)
Pre'97	($1,024,135)
Post'96	($5,343,554)

Initial Billing Period	Pre 1997 Balance	Post 1996 Balance	FERC Monthly Interest Rate	Pre 1997 Interest	Post 1996 Interest
June 2010	(1,024,135)	(5,343,554)	0.27%	-2,765	($14,428)
July 2010	(1,026,900)	(5,357,981)	0.28%	-2,875	($15,002)
August 2010	(1,026,900)	(5,357,981)	0.28%	-2,875	($15,002)
September 2010	(1,026,900)	(5,357,981)	0.27%	-2,773	($14,467)
October 2010	(1,035,423)	(5,402,453)	0.28%	-2,899	($15,127)
November 2010	(1,035,423)	(5,402,453)	0.27%	-2,796	($14,587)
December 2010	(1,035,423)	(5,402,453)	0.28%	-2,899	($15,127)
January 2011	(1,044,017)	(5,447,293)	0.28%	-2,923	($15,252)
February 2011	(1,044,017)	(5,447,293)	0.25%	-2,610	($13,618)
March 2011	(1,044,017)	(5,447,293)	0.28%	-2,923	($15,252)
April 2011	(1,052,474)	(5,491,416)	0.27%	-2,842	($14,827)
May 2011	(1,052,474)	(5,491,416)	0.28%	-2,947	($15,376)
		Total Interest		-$34,128	-$178,065
		True-Up		-$1,024,135	-$5,343,554
		Total TU & Int		**-$1,058,262**	**-$5,521,619**

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: 16-May-11

Revenue Requirements for (year): Calendar Year2010

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	=	0	(a)	0	(f)
Total of Attachment F - Section J - Support Revenue		0	(b)	0	(g)
Total of Attachment F - Section K - Support Expense		124,419	(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)		124,419	(e)=(a)-(b)+(c)+(d)	0	(j)
Forecasted Transmission Revenue Requirements (per Appendix C to Attachment F Implementation Rule)		N/A		N/A	(k) Worksheet 1a
Annual True-up (per Appendix C to Attachment F Implementation Rule)		$0	(l)	$0	(m) Worksheet 1c
Adjusted Sub Total - Sum (Sub Total + forecast + True-up		$124,419	(n) = (e) + (l)	$0	(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) $124,419 (p) = (n) + (o)

Unitil Power Corp.
Annual Revenue Requirements of PTF Facilities
for costs in 2010
PRE-1997

▨ Shading denotes an input

Line No.	I. INVESTMENT BASE	Attachment F Reference *Section:*	UPC	Total	Reference
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)	124,419	124,419	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)		124,419	124,419	

Unitil Power Corp.
Annual Revenue Requirements
for costs in 2010

▨ 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

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

$$= \frac{(\text{\#DIV/0!} + (0 + 0) / 0) \times 0.34)}{(1 - 0.34)}$$

$$= \text{\#DIV/0!}$$

(c) State Income Tax

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

$$= \frac{(\text{\#DIV/0!} + (0 + 0) / 0) + \text{\#DIV/0!})\text{*} \ 0.085}{(1 - 0.085)}$$

$$= \text{\#DIV/0!}$$

(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.

Sheet: Worksheet 3

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)
	Transmission Plant							
1	Transmission Plant				0		0	Line 1, Worksheet 5
2	General Plant	0	#DIV/0!	(a)	#DIV/0!	#DIV/0!	#DIV/0!	Page 207.83g
3	Total (line 1+2)				#DIV/0!		#DIV/0!	
4	Transmission Plant Held for Future Us	0			0	#DIV/0!	#DIV/0!	Page 214
	Transmission Accumulated Depreciation							
5	Transmission Accum. Depreciation	0			0	#DIV/0!	#DIV/0!	Page 219.23b
6	General Plant Accum.Depreciation	0	#DIV/0!	(a)	#DIV/0!	#DIV/0!	#DIV/0!	Page 219.25b
7	Total (line 5+6)				#DIV/0!		#DIV/0!	
	Transmission Accumulated Deferred Taxes							
8	Accumulated Deferred Taxes (281-283)	0	#DIV/0!	(c)	#DIV/0!	#DIV/0!	#DIV/0!	**Page 275.2k + 277.9k (d)**
9	Accumulated Deferred Taxes (190)	0	#DIV/0!	(c)	#DIV/0!	#DIV/0!	#DIV/0!	**Page 234.8c (d)**
10	Total (line 8+9)				#DIV/0!		#DIV/0!	
11	Transmission loss on Reacquired Deb	0	#DIV/0!	(c)	#DIV/0!	#DIV/0!	#DIV/0!	Page 111.65d
	Other Regulatory Assets							
12	FAS 106	0	#DIV/0!	(a)	#DIV/0!	#DIV/0!	#DIV/0!	Page 232.30e
13	FAS 109	0	#DIV/0!	(c)	#DIV/0!	#DIV/0!	#DIV/0!	**Page 233.1f - 269.1f (d)**
14	Other Regulatory Liabilities (254.DK)	0	#DIV/0!	(c)	#DIV/0!	#DIV/0!	#DIV/0!	
15	Total (line 12+13+14	0			#DIV/0!		#DIV/0!	
16	Transmission Prepayments	0	#DIV/0!	(a)	#DIV/0!	#DIV/0!	#DIV/0!	**Page 110.46d*p.200.8.c/p.200.8.**
17	Transmission Materials and Supplie	0			0	#DIV/0!	#DIV/0!	Page 227.8c
18	Cash Working Capital							
19	Operation & Maintenance Expense						0	Worksheet 1, Line 20
20	Administrative & General Expense						0	Worksheet 1, Line 21
21	Transmission Support Expense						124,419	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)						124,419	
23							0.125	x 45 / 360
24	Total (line 22 * line 23						15,552	

(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

Sheet: Worksheet 4

🟨 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)
	Depreciation Expense							
1	Transmission Depreciation	0			0	#DIV/0!	#DIV/0!	Page 336.7b
2	General Depreciation	0	#DIV/0!	(a)	#DIV/0!	#DIV/0!	#DIV/0!	Page 336.9b
3	Total (line 1+2)				#DIV/0!		#DIV/0!	
4	Amortization of Loss on Reacquired Debt	0	#DIV/0!	(c)	#DIV/0!	#DIV/0!	#DIV/0!	Page 117.58c
5	Amortization of Investment Tax Credits	0	#DIV/0!	(c)	#DIV/0!	#DIV/0!	#DIV/0!	Page 266.8f
	Property Taxes							
6	Transmission Property Taxes	0	#DIV/0!	(c)	#DIV/0!	#DIV/0!	#DIV/0!	**Page 262i-263i (e)**
7	General Property Taxes	0	#DIV/0!	(a)	#DIV/0!	#DIV/0!	#DIV/0!	Page 262-263
8	Total (line 6+7)				#DIV/0!		#DIV/0!	
	Transmission Operation and Maintenance							
9	Operation and Maintenance	0			0	#DIV/0!	#DIV/0!	Page 321.100b
10	Transmission of Electricity by Others - #565	0			0	#DIV/0!	#DIV/0!	Page 321.88b
11	Load Dispatching - #561	0			0	#DIV/0!	#DIV/0!	Page 321.84b
12	**Station Expenses & Rents- #562 / #567						0	Page 321.85b & .90b
13	O&M less lines 10, 11 & 12	0			0	#DIV/0!	#DIV/0!	
	Transmission Administrative and General							
14	Administrative and General	0						Page 323.168b
15	*less Property Insurance (#924)*	*0*						*Page 323.156b*
16	*less Regulatory Commission Expenses (#928)*	*0*						*Page 350*
17	*less General Advertising Expense (#930.1)*	*0*						*Page 323.162b*
18	Subtotal [line 14 minus (15 thru 17)]	0	#DIV/0!	(a)	#DIV/0!	#DIV/0!	#DIV/0!	
19	*PLUS Property Insurance alloc. using Plant Allocation*	*0*	*#DIV/0!*	*(c)*	#DIV/0!	#DIV/0!	#DIV/0!	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	*0*	*#DIV/0!*	*(c)*	#DIV/0!	#DIV/0!	#DIV/0!	
21	*PLUS Trans. Related General Advertising Expense*	*0*	*#DIV/0!*	*(c)*	#DIV/0!	#DIV/0!	#DIV/0!	
22	Total A&G [line 18 plus (19 thru 21)]	*0*			*#DIV/0!*		*#DIV/0!*	
23	*Payroll Tax Expense*	*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
	PTF Transmission Plant Allocation Factor	**UPC**	
1	PTF Transmission Investment	0	See Workpaper 1
2	Total Transmission Investment	0	Page 207.53g
3	Percent Allocation (Line 1/Line 2)	#DIV/0!	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	0	Page 354.19b
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	0	Page 354.25b + Line 5
8	Administrative and General Wages and Salaries	0	Page 354.24b
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)	0	
11	Percent Allocation (Line 6/Line 10)	#DIV/0!	
	Plant Allocation Factor		
12	Total Transmission Investment	0	Page 207.53g
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	#DIV/0!	*Worksheet 3, Line 2*
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!	

Sheet: Worksheet 6

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		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.

		UPC		TOTAL	
Participant	PTF Supporting Facilities	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	5,681	0	5,681
	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	33,607	0	33,607
	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	85,131	0	85,131
	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	124,419	0	124,419

Amount by which Support Expense exceeds Support Revenues (To Worksheet 3, Line 21, Column 5)	124,419

See Workpaper 1.

Sheet: Worksheet 8

RNS Rate
Workpaper 8 of 8

Summary of Unitil Power Corp. System
Monthly Coincident Peaks for 2010
(Megawatts)

🟨 Shading denotes an input

	JAN '10	FEB '10	MAR '10	APR '10	MAY '10	JUN '10	JUL '10	AUG '10	SEP '10	OCT '10	NOV '10	DEC '10
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.

File: K:\conadm\test\ehv\rtg\Ancil95.xls

Workpaper 1
Unitil Power Corp
Transmission Support Payment Accounts

		2010	
13-20-13-00-565-11-01-00	HQ - BECO AC (d/b/a NSTAR)	5,680.61	
13-20-13-00-565-46-00-00	HQ II TRANS EXP - BECO	$ -	
	Total	$ 5,680.61	Worksheet 7, BECo HQ Phase II - AC in MA
13-20-13-00-565-11-02	HQ - NEP AC	85,131.39	Worksheet 7, NEP HQ Phase II - AC in MA
13-20-13-00-565-11-03	HQ - Chester SVC	33,607.15	Worksheet 7, NEP Chester SVC

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

Submitted on:	May 12, 2011
Revenue Requirements for (test year):	Calendar Year 2010
Rates Effective for the period:	June 1, 2011
through:	May 31, 2012
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	=	$ 10,425,382	(a)	$ 92,886,237	(f)
Total of Attachment F - Section J - Support Revenue		-	(b)	-	(g)
Total of Attachment F - Section K - Support Expense		1,025,535	(c)	-	(h)
Total of Attachment F - Section (L through O)		(10)	(d)	(90)	(i)
Sub Total - Sum (A through I) - J + K + (L through O)		11,450,906	(e)=(a)-(b)+(c)+(d)	92,886,147	(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)		N/A		3,420,235	(k)
Annual True-up (per Attachment C to Attachment F Implementation Rule)		(348,418)	(l)	(7,214,579)	(m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)		**$ 11,102,488**	(n)=(e)+(l)	**$ 89,091,802**	(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) **$ 100,194,290** (p) = (n)+(o)

VT TRANSCO
Annual Revenue Requirements of PTF Facilities
2010

			Attachment F Reference	PRE 97	POST 1996	TOTAL	Ref
	I.	INVESTMENT BASE					
Line No.			*Section:*				
1		Transmission Plant	(A)(1)(a)	$ 63,301,109	$ 552,481,549	$ 615,782,658	Worksheet 1
2		General Plant	(A)(1)(b)	4,002,372	34,931,936	38,934,308	Worksheet 1
3		Plant Held For Future Use	(A)(1)(c)	154,356	1,347,187	1,501,543	Worksheet 1
4		Total Plant (Lines 1+2+3)		67,457,837	588,760,672	656,218,509	
5		Accumulated Depreciation	(A)(1)(d)	8,882,827	77,527,610	86,410,437	Worksheet 1
6		Accumulated Deferred Income Taxes	(A)(1)(e)	3,757,444	32,794,252	36,551,696	Worksheet 1
7		Loss On Reacquired Debt	(A)(1)(f)	-	-	-	Worksheet 1
8		Other Regulatory Assets	(A)(1)(g)	-	-	-	Worksheet 1
9		Net Investment (Line 4-5-6+7+8)		54,817,566	478,438,810	533,256,376	
10		Prepayments	(A)(1)(h)	46,337	404,418	450,755	Worksheet 1
11		Materials & Supplies	(A)(1)(i)	595,101	5,193,930	5,789,031	Worksheet 1
12		Cash Working Capital	(A)(1)(j)	268,081	1,220,924	1,489,005	Worksheet 1
13		Total Investment Base (Line 9+10+11+12)		$ 55,727,085	$ 485,258,082	$ 540,985,167	Worksheet 1
	II.	REVENUE REQUIREMENTS					
14		Investment Return and Income Taxes	(A)	$ 7,171,920	$ 64,490,636	$ 71,662,556	Worksheet 1
15		Depreciation Expense	(B)	1,229,433	10,730,256	11,959,689	Worksheet 1
16		Amortization of Loss on Reacquired Debt	(C)	-	-	-	Worksheet 1
17		Investment Tax Credit	(D)	-	-	-	Worksheet 1
18		Property Tax Expense	(E)	822,156	7,175,620	7,997,776	Worksheet 1
19		Payroll Tax Expense	(F)	82,762	722,332	805,094	
20		Operation & Maintenance Expense	(G)	645,449	5,633,359	6,278,808	Worksheet 1
21		Administrative & General Expense	(H)	473,662	4,134,034	4,607,696	Worksheet 1
22		Transmission Related Integrated Facilities Charge	(I)	-	-	-	Worksheet 1
23		Transmission Support Revenue	(J)	-	-	-	Worksheet 1
24		Transmission Support Expense	(K)	1,025,535	-	1,025,535	Worksheet 1
25		Transmission Related Expense from Generators	(L)	-	-	-	
26		Transmission Related Taxes and Fees Charge	(M)	42,923	374,627	417,550	
27		Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(41,165)	(359,276)	(400,440)	Worksheet 1
28		Transmission Rents Received from Electric Property	(O)	(1,769)	(15,442)	(17,211)	
29		Total RNS Revenue Requirements before Forecast, Annual True-up and Assoc. Interest (Line 14 thru 28)		$ 11,450,906	$ 92,886,147	$ 104,337,053	

VT TRANSCO
Annual Revenue Requirements of PTF Facilities
2009

			Attachment F Reference Section:	PRE97	POST 1996	TOTAL	Reference
	I.	INVESTMENT BASE					
Line No.							
1		Transmission Plant	(A)(1)(a)	$ 63,177,846	$ 373,426,415	$ 436,604,261	Worksheet 3, line 1&2 column 5
2		General Plant	(A)(1)(b)	3,975,243	23,496,475	27,471,718	Worksheet 3, line 3 column 5
3		Plant Held For Future Use	(A)(1)(c)	209,910	1,240,715	1,450,625	Worksheet 3, line 5 column 5
4		Total Plant (Lines 1+2+3)		67,362,999	398,163,605	465,526,604	
5		Accumulated Depreciation	(A)(1)(d)	10,923,208	64,563,826	75,487,034	Worksheet 3, line 8 column 5
6		Accumulated Deferred Income Taxes	(A)(1)(e)	3,827,266	22,621,829	26,449,095	Worksheet 3, line 11 column 5
7		Loss On Reacquired Debt	(A)(1)(f)	-	-	-	Worksheet 3, line 12 column 5
8		Other Regulatory Assets	(A)(1)(g)	-	-	-	Worksheet 3, line 16 column 5
9		Net Investment (Line 4-5-6+7+8)		52,612,525	310,977,950	363,590,475	
10		Prepayments	(A)(1)(h)	85,203	503,608	588,811	Worksheet 3, line 17 column 5
11		Materials & Supplies	(A)(1)(i)	681,068	4,025,589	4,706,657	Worksheet 3, line 18 column 5
12		Cash Working Capital	(A)(1)(j)	321,418	1,151,140	1,472,558	Worksheet 3, line 25 column 5
13		Total Investment Base (Line 9+10+11+12)		$ 53,700,214	$ 316,658,287	$ 370,358,501	
	II.	REVENUE REQUIREMENTS					
14		Investment Return and Income Taxes	(A)	$ 6,515,479	$ 40,203,888	$ 46,719,367	Worksheet 2
15		Depreciation Expense	(B)	1,545,263	9,133,590	10,678,853	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)	1,015,934	6,004,886	7,020,820	Worksheet 4, line 6, column 5
19		Payroll Tax Expense	(F)	106,335	628,514	734,849	Worksheet 4, line 22, column 5
20		Operation & Maintenance Expense	(G)	678,105	4,008,073	4,686,178	Worksheet 4, line 11, column 5
21		Administrative & General Expense	(H)	879,936	5,201,046	6,080,982	Worksheet 4, line 21, column 5
22		Transmission Related Integrated Facilities Charge	(I)	-	-	-	Attachment 4, line 6
23		Transmission Support Revenue	(J)	-	-	-	Worksheet 6
24		Transmission Support Expense	(K)	1,013,305	-	1,013,305	Worksheet 6
25		Transmission Related Expense from Generators	(L)	-	-	-	Worksheet 7
26		Transmission Related Taxes and Fees Charge	(M)	52,131	308,130	360,261	
27		Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(17,862)	(105,578)	(123,440)	Attachment 7
28		Transmission Rents Received from Electric Property	(O)	(538)	(3,177)	(3,715)	Attachment 6
29		Total RNS Revenue Requirements before Forecast, Annual True-up and Assoc. Interest (Line 14 thru 28)		$ 11,788,089	$ 65,379,372	$ 77,167,461	
30		Forecasted PTF Revenue Requirements - 2010		-	34,488,693	34,488,693	
31		Total RNS Rev Req'ts subject to Annual True-up		$ 11,788,089	$ 99,868,065	$ 111,656,154	
32		PY true-up		(666,329)	(5,392,721)	(6,059,050)	
33		Total RNS-6/1/10-5/31/11		$ 11,121,760	$ 94,475,344	$ 105,597,104	

VT TRANSCO
Transmission Revenue Requirements of PTF Facilities
2010 True-up

I.	**APPENDIX C - ANNUAL TRUE-UP**	**Rate Year**	**PRE97**	**POST 1996**	**Total**	**Reference**
1	ATRR for True-up = 2010 Actual	6/1/11-5/31/12	$ 11,450,906	$ 92,886,147	$ 104,337,053	Summary 6-1-11_5-31-12, line 29
2	ATRR subject to True-up = '09 TY + '10 Forecast -	6/1/10-5/31/11	11,788,089	99,868,065	111,656,154	Summary 6-1-10_5-31-11, line 31
3	Annual True-up (Line 1 - Line 2)		$ (337,182)	$ (6,981,918)	$ (7,319,101)	

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

	Undercollection / (Overcollection)
PRE97	(337,182)
Post1996	(6,981,918)

Initial Billing Period	PRE97 Balance	POST 1996 Balance	FERC Monthly Interest Rate	PRE97 Interest	POST 1996 Interest	
June 2010	(337,182)	(6,981,918)	0.27%	$ (910.39)	$ (18,851.18)	
July 2010	(338,093)	(7,000,770)	0.28%	(946.66)	(19,602.15)	
August 2010	(338,093)	(7,000,770)	0.28%	(946.66)	(19,602.15)	
September 2010	(338,093)	(7,000,770)	0.27%	(912.85)	(18,902.08)	
October 2010	(340,899)	(7,058,876)	0.28%	(954.52)	(19,764.85)	
November 2010	(340,899)	(7,058,876)	0.27%	(920.43)	(19,058.97)	
December 2010	(340,899)	(7,058,876)	0.28%	(954.52)	(19,764.85)	
January 2011	(343,728)	(7,117,465)	0.28%	(962.44)	(19,928.90)	
February 2011	(343,728)	(7,117,465)	0.25%	(859.32)	(17,793.66)	
March 2011	(343,728)	(7,117,465)	0.28%	(962.44)	(19,928.90)	
April 2011	(346,512)	(7,175,116)	0.27%	(935.58)	(19,372.81)	
May 2011	(346,512)	(7,175,116)	0.28%	(970.23)	(20,090.33)	
		Total Interest		$ (11,236)	$ (232,661)	$ (243,897)
		True-Up		(337,182)	(6,981,918)	(7,319,101)
		Total TU & Int		$ (348,418)	$ (7,214,579)	$ (7,562,998)

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 12, 2011
Revenue Requirements for (year):	**Calendar Yr 2010** $ 100,194,290
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	=	10,425,382	(a)	92,886,237	(f)
Total of Attachment F - Section J - Support Revenue		0	(b)		(g)
Total of Attachment F - Section K - Support Expense		1,025,535	(c)		(h)
Total of Attachment F - Section (L through O)		(10)	(d)	(90)	(i)
Sub Total - Sum (A through I) - J + K + (L through O)		11,450,906	(e)=(a)-(b)+(c)+(d)	92,886,147	(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)		N/A		3,420,235	(k) = (e) + (j)
Annual True-up (per Attachment C to Attachment F Implementation Rule		($348,418)	(l)	($7,214,579)	(m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)		11,102,488	(n)=(e)+(l)	89,091,802	(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)	**100,194,290**	(p)=(n)+(o)

VT TRANSCO

Annual Revenue Requirements of PTF Facilities
for costs in 2010

PTF Revenue Requirements
Worksheet 1 of 8

▨ Shading denotes an input

Line N	I. INVESTMENT BASE	Attachment F Reference *Section:*	Total	
1	Transmission Plant	(A)(1)(a)	615,782,658	
2	General Plant	(A)(1)(b)	38,934,308	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	1,501,542	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		656,218,508	
5	Accumulated Depreciation	(A)(1)(d)	86,410,437	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	36,551,696	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)		533,256,375	
10	Prepayments	(A)(1)(h)	450,754	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	5,789,032	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	1,489,005	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		540,985,166	
	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	69,623,276	Worksheet 2
	Investment Return and Income Taxes		2,039,279	Worksheet adder
15	Depreciation Expense	(B)	11,959,689	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)	7,997,776	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	805,094	*Worksheet 4, line 23 column 5*
20	Operation & Maintenance Expense	(G)	6,278,808	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	4,607,697	Worksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Charg	(I)	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	1,025,535	Worksheet 7
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	417,550	Gross Revenue Tax
27	Revenue for ST Trans. Service Under NEPOOL	(N)	(400,440)	Schedule 8 TOUT Revenues
28	Transmission Rents Received from Electric Prop	(O)	(17,211)	Rev Rent 4000-454122
29	Total Revenue Requirements (Line 14 thru 28)		104,337,053	

VT TRANSCO
Annual Revenue Requirements
for costs in 2010

▨ Shading denotes an input

		CAPITALIZATION 12/31/10	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTIO
LONG-TERM DEBT	$	329,093,000	46.59%	5.51%	2.57%	
PREFERRED STOCK		0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY		377,299,526	53.42%	11.64%	6.22%	6.22%
TOTAL INVESTMEN	$	706,392,526	100.01%		8.79%	6.22%

Cost of Capital Rate=

(a) Weighted Cost c = 0.0879

(b) Federal Income = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Depre) / PTF Inv. Base) x Federal Income Tax Rate)
(- Federal Income Tax Rate)

= 0.0622 + 0 + 0 ` 540,985,166) x 0.34)
(1 - 0.34)

= 0.0320424

(c) State Income Ta = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Depre) / PTF Inv. Base) + Federal Income Tax)* State Income Ta
(1 - State Income Tax Rate)

= 0.0622 + 0 + 0) / 540,985,166) + 0.0320424)* 0.085
(1 - 0.085)

= 0.0087548

(a)+(b)+(c) **Cost of** = 0.1286972

		(PTF)	
INVESTMENT BASE	$	540,985,166	From Worksheet 1
x Cost of Capital Rate		0.1286972	
= Investment Return and		69,623,276	To Worksheet 1

🟨 Shading denotes an input

.ine 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)
	Transmission Plant						
1	Transmission Plant	764,388,526		764,388,526		615,782,658	Line 1, Worksheet 5
2	General Plant	48,330,238	100.0000% (a	48,330,238	80.5589%	38,934,308	Page 207.99g
3	Total (line 1+2)			812,718,764		654,716,966	
4	Transmission Plant Held for Future Use	1,863,906		1,863,906	80.5589%	1,501,542	Page 214.47d
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	89,794,230		89,794,230	80.5589%	72,337,244	Page 219.25b
6	General Plant Accum.Depreciation	17,469,445	100.0000% (a	17,469,445	80.5589%	14,073,193	Page 219.27b
7	Total (line 5+6)			107,263,675		86,410,437	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	(45,732,229)	99.2137% (c	(45,372,636)	80.5589%	(36,551,696)	Page 113.63d
9	Accumulated Deferred Taxes (190)	0	99.2137% (c	0	80.5589%	0	Page 111.68d
10	Total (line 8+9)			(45,372,636)		(36,551,696)	
11	Transmission loss on Reacquired Debt	0	99.2137% (c	0	80.5589%	0	Page 111.81d
	Other Regulatory Assets						
12	FAS 106	0	100.0000% (a	0	80.5589%	0	Page 232.30e
13	FAS 109	0	99.2137% (c	0	80.5589%	0	Page 232.21&23e
14	Other Regulatory Liabilities (254.DK)	0	99.2137% (c	0	80.5589%	0	Page 278.1e
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments	559,534	100.0000% (a	559,534	80.5589%	450,754	Page 111.57c
17	Transmission Materials and Supplies	7,186,086		7,186,086	80.5589%	5,789,032	Page 227.8c
18	Cash Working Capital						
19	Operation & Maintenance Expense					6,278,808	Worksheet 1, Line 20
20	Administrative & General Expense					4,607,697	Worksheet 1, Line 21
21	Transmission Support Expense					1,025,535	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					11,912,040	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					1,489,005	

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

VT TRANSCO

Sheet: Worksheet 4

▨ 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)
	Depreciation Expense						
1	Transmission Depreciation	11,768,120		11,768,120	80.5589%	9,480,268	Page 336.7b
2	General Depreciation	3,077,774	100.0000% (a)	3,077,774	80.5589%	2,479,421	Page 336.9b
3	Total (line 1+2)			14,845,894		11,959,689	
4	Amortization of Loss on Reacquired I	0	99.2137% (c)	0 C	80.5589%	0	Page 117.64c
5	Amortization of Investment Tax Credits		99.2137% (c)	0	80.5589%	0	Page 266.8f
	Property Taxes *						
6	Transmission Property Taxes	9,927,862	99.2137% (c)	9,927,862	80.5589%	7,997,776	Page 262-263 FN.1-2
7	General Property Taxes			0	80.5589%	0	Page 262-263 FN.1-2
8	Total (line 6+7)			9,927,862		7,997,776	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	10,604,067		10,604,067	80.5589%	8,542,520	Page 321.112b
10	Transmission of Electricity by Others	586,968		586,968	80.5589%	472,855	Page 321.96b
11	Load Dispatching - #561.1-561.4	2,178,858		2,178,858	80.5589%	1,755,264	Page 321.84 - 88b
12	**Station Expenses & Rents - #562 / #56	44,183		44,183	80.5589%	35,593	Page 321.93b & .98b
13	O&M less lines 10, 11 & 12	7,794,058		7,794,058	`	6,278,808	
	Transmission Administrative and General						
14	Administrative and General	5,727,347					Page 323.197b
15	*less Property Insurance (#924)*	*671,643*					*Page 323.185b*
16	*less Regulatory Commission Expenses (#928)*	*258,720*					*Page 323.189b*
17	*less General Advertising Expense (#930.1)*	*47,056*					*Page 323.191b*
18	Subtotal [line 14 minus (15 thru 17)]	4,749,928	100.0000% (a)	4,749,928	80.5589%	3,826,490	
19	*PLUS Property Insurance alloc. using Plant Allocati*	*671,643*	99.2137% *(c*	666,362	80.5589%	536,814	
20	*PLUS Regulatory Comm. Exp. (FERC Assessment*	*258,720*	99.2137% *(c*	256,686	80.5589%	206,783	
21	*PLUS Trans. Related General Advertising Expense*	*47,056*	99.2137% *(c*	46,686	80.5589%	37,610	
22	Total A&G [line 18 plus (19 thru 21)]	*5,727,347*		*5,719,662*		*4,607,697*	
23	*Payroll Tax Expense*	*999,386*	100.0000% *(a)*	*999,386*	80.5589%	*805,094*	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	9,039	
FICA	948,258	
Medicare	0	
CT Unemployment	0	
MA Unemployment	0	
MA Universal Health	0	
VT Unemployment	42,089	
NH Unemployment	0	
Total	999,386	*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 Fact	**VT TRANSCO**		
1	PTF Transmission Investment	615,782,658	NEPOOL Catalog	
2	Total Transmission Investment	764,388,526	Page 207.58g	Includes Benn-Searsburg line
3	Percent Allocation (Line 1/Line 2)	80.5589%		
	Transmission Wages and Salaries Allocation Factor			
4	Direct Transmission Wages and Salaries	5,158,883	Page 354.21b	
5	Affiliated Company Transmission Wages and S	0	Worksheet 6 & 6a of 8	
6	Total Transmission Wages and Salaries (L	5,158,883		
7	Total Wages and Salaries	9,408,987	Page 354.28b	
8	Administrative and General Wages and Salarie	4,250,104	Page 354.27b	
9	Affiliated Company Wages and Salaries less A	0	Worksheet 6 & 6a of 8	
10	Total Wages and Salaries net of A&G (Lin	5,158,883		
11	Percent Allocation (Line 6/Line 10)	100.0000%		`
	Plant Allocation Factor			
12	Total Transmission Investment	764,388,526	Page 207.58g	Includes Benn-Searsburg line
13	*plus Transmission-Related General Plant (Lin*	48,330,238	*Page 207.99g*	
14	*= Revised Numerator (Line 12 + Line 13)*	812,718,764		
15	Total Plant in Service	819,159,493	Page 207.104g	Includes Benn-Searsburg line
16	Percent Allocation (Line 14 / Line 15)	99.2137%		

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 1(	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)	TOTAL 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]		40,290
	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**			12,657
	115 kV Wyman 164-167 lines			4,750
	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**			252,852
	Comerford 115 kV Substation			44,183
	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]		610,162
	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)		60,641
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
		Total =	0	1,025,535

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

PRE-97

Submitted on: May 12, 2011

Revenue Requirements for (year): **Calendar Yr 2010** $ 11,450,906

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	=	10,425,382	(a)		(f)
Total of Attachment F - Section J - Support Revenue		0	(b)		(g)
Total of Attachment F - Section K - Support Expense		1,025,535	(c)		(h)
Total of Attachment F - Section (L through O)		(10)	(d)		(i)
Sub Total - Sum (A through I) - J + K + (L through O)		11,450,906	(e)=(a)-(b)+(c)+(d)	-	(j)

Pre-97 Revenue Requirements (per Attachment C to Attachment F Implementation Rule	11,450,906	(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 Pre-97 Revenue Requirements	11,450,906	(l)=(k)+(b)+(g)-(h)

VT TRANSCO
Annual Revenue Requirements of PTF Facilities
for costs in 2010

PTF Revenue Requirements
Worksheet 1 of 8

🟨 Shading denotes an input

Line N	I. INVESTMENT BASE	Attachment F Reference Section:	Total	Reference
1	Transmission Plant	(A)(1)(a)	63,301,109	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	4,002,372	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	154,356	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		67,457,837	
5	Accumulated Depreciation	(A)(1)(d)	8,882,827	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	3,757,444	Vorksheet 3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	0	Vorksheet 3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	0	Vorksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		54,817,566	
10	Prepayments	(A)(1)(h)	46,337	Vorksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	595,101	Vorksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	268,081	Vorksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		55,727,085	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	7,171,920	Worksheet 2
15	Depreciation Expense	(B)	1,229,433	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)	822,156	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	82,762	*Vorksheet 4, line 23 column 5*
20	Operation & Maintenance Expense	(G)	645,449	Vorksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	473,662	Vorksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Charg	(I)	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	1,025,535	Worksheet 7
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	42,923	Gross Revenue Tax
27	Revenue for ST Trans. Service Under NEPOOL	(N)	(41,165)	Schedule 8 TOUT Revenues
28	Transmission Rents Received from Electric Prop	(O)	(1,769)	Rev Rent 4000-454122
29	Total Revenue Requirements (Line 14 thru 28)		11,450,906	

VT TRANSCO

Annual Revenue Requirements
for costs in 2010

▨ Shading denotes an input

		CAPITALIZATION 12/31/10		CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTIO
LONG-TERM DEBT	$	329,093,000	Page 112.24c	46.59%	5.51%	2.57%	
PREFERRED STOCK		0		0.00%	0.00%	0.00%	0.00%
COMMON EQUITY		377,299,526	Page 112.16c	53.42%	11.64%	6.22%	6.22%
TOTAL INVESTMEN	$	706,392,526		100.01%		8.79%	6.22%

Cost of Capital Rate=

(a) Weighted Cost o = 0.0879

(b) Federal Income ' = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Depre) / PTF Inv. Base) x Federal Income Tax Rate)
(1 - Federal Income Tax Rate)

= 0.0622 + 0 + 0 ` 55,727,085) x 0.34)
(1 - 0.34)

= 0.0320424

(c) State Income Ta = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Depre) / PTF Inv. Base) + Federal Income Tax)* State Income Ta
(1 - State Income Tax Rate)

= 0.0622 + 0 + 0) / 55,727,085) + 0.0320424)* 0.085
(1 - 0.085)

= 0.0087548

(a)+(b)+(c) **Cost of** = 0.1286972

		(PTF)	
INVESTMENT BASE	$	55,727,085	From Worksheet 1
x Cost of Capital Rate		0.1286972	
= Investment Return and		7,171,920	To Worksheet 1

🟨 Shading denotes an input

ine 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)
	Transmission Plant						
1	Transmission Plant	764,388,526		764,388,526		63,301,109	Line 1, Worksheet 5
2	General Plant	48,330,238	100.0000% (a	48,330,238	8.2813%	4,002,372	Page 207.99g
3	Total (line 1+2)			812,718,764		67,303,481	
4	Transmission Plant Held for Future	1,863,906		1,863,906	8.2813%	154,356	Page 214.47d
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	89,794,230		89,794,230	8.2813%	7,436,130	Page 219.25b
6	General Plant Accum.Depreciation	17,469,445	100.0000% (a	17,469,445	8.2813%	1,446,697	Page 219.27b
7	Total (line 5+6)			107,263,675		8,882,827	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281	(45,732,229)	99.2137% (c	(45,372,636)	8.2813%	(3,757,444)	Page 113.63d
9	Accumulated Deferred Taxes (19C	0	99.2137% (c	0	8.2813%	0	Page 111.82d
10	Total (line 8+9)			(45,372,636)		(3,757,444)	
11	Transmission loss on Reacquired I	0	99.2137% (c	0	8.2813%	0	Page 111.81d
	Other Regulatory Assets						
12	FAS 106	0	100.0000% (a	0	8.2813%	0	Page 232.30e
13	FAS 109	0	99.2137% (c	0	8.2813%	0	Page 232.21&23e
14	Other Regulatory Liabilities (254.I	0	99.2137% (c	0	8.2813%	0	Page 278.1e
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments (165)	559,534	100.0000% (a	559,534	8.2813%	46,337	Page 111.57c
17	Transmission Materials and Suppli	7,186,086		7,186,086	8.2813%	595,101	Page 227.8c
18	Cash Working Capital						
19	Operation & Maintenance Expense					645,449	Worksheet 1, Line 20
20	Administrative & General Expense					473,662	Worksheet 1, Line 21
21	Transmission Support Expense					1,025,535	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					2,144,646	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					268,081	

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

VT TRANSCO

Sheet: Worksheet 4

▨ Shading denotes an input

.ine 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	Transmission Depreciation	11,768,120		11,768,120	8.2813%	974,553	Page 336.7b
2	General Depreciation	3,077,774	100.0000% (a)	3,077,774	8.2813%	254,880	Page 336.9b
3	Total (line 1+2)			14,845,894		1,229,433	
4	Amortization of Loss on Reacquired D	0	99.2137% (c)	0	8.2813%	0	Page 117.64c
5	Amortization of Investment Tax Credits		99.2137% (c)	0	8.2813%	0	Page 266.8f
	Property Taxes *						
6	Transmission Property Taxes	9,927,862	99.2137% (c)	9,927,862	8.2813%	822,156	Page 262-263 FN.1-2
7	General Property Taxes			0	8.2813%	0	Page 262-263 FN.1-2
8	Total (line 6+7)			9,927,862		822,156	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	10,604,067		10,604,067	8.2813%	878,155	Page 321.112b
10	Transmission of Electricity by Others	586,968		586,968	8.2813%	48,609	Page 321.96b
11	Load Dispatching - #561.1-561.4	2,178,858		2,178,858	8.2813%	180,438	Page 321.84 - 88b
12	**Station Expenses & Rents - #562 / #567	44,183		44,183	8.2813%	3,659	Page 321.93b & .98b
13	O&M less lines 10, 11 & 12	7,794,058		7,794,058	`	645,449	
	Transmission Administrative and General						
14	Administrative and General	5,727,347					Page 323.197b
15	*less Property Insurance (#924)*	*671,643*					*Page 323.185b*
16	*less Regulatory Commission Expenses (#928)*	*258,720*					*Page 323.189b*
17	*less General Advertising Expense (#930.1)*	*47,056*					*Page 323.191b*
18	Subtotal [line 14 minus (15 thru 17)]	4,749,928	100.0000% (a)	4,749,928	8.2813%	393,356	
19	*PLUS Property Insurance alloc. using Plant Allocatio*	*671,643*	99.2137% *(c)*	666,362	8.2813%	55,183	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	*258,720*	99.2137% *(c)*	256,686	8.2813%	21,257	
21	*PLUS Trans. Related General Advertising Expense*	*47,056*	99.2137% *(c)*	46,686	8.2813%	3,866	
22	Total A&G [line 18 plus (19 thru 21)]	*5,727,347*		*5,719,662*		*473,662*	
23	*Payroll Tax Expense*	*999,386*	100.0000% *(a)*	*999,386*	8.2813%	*82,762*	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	9,039	
FICA	948,258	
Medicare	0	
CT Unemployment	0	
MA Unemployment	0	
MA Universal Health	0	
VT Unemployment	42,089	
NH Unemployment	0	
Total	999,386	*To Line 23*

** Subtract Accounts #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 Fact	**VT TRANSCO**		
1	PTF Transmission Investment	63,301,109	NEPOOL Catalog	
2	Total Transmission Investment	764,388,526	Page 207.58g	Includes Benn-Searsburg line
3	Percent Allocation (Line 1/Line 2)	8.2813%		
	Transmission Wages and Salaries Allocation Factor			
4	Direct Transmission Wages and Salaries	5,158,883	Page 354.21b	
5	Affiliated Company Transmission Wages and S	0	Worksheet 6 & 6a of 8	
6	Total Transmission Wages and Salaries (Li	5,158,883		
7	Total Wages and Salaries	9,408,987	Page 354.28b	
8	Administrative and General Wages and Salarie	4,250,104	Page 354.27b	
9	Affiliated Company Wages and Salaries less A8	0	Worksheet 6 & 6a of 8	
10	Total Wages and Salaries net of A&G (Line	5,158,883		
11	Percent Allocation (Line 6/Line 10)	100.0000%		`
	Plant Allocation Factor			
12	Total Transmission Investment	764,388,526	Page 207.58g	Includes Benn-Searsburg line
13	*plus Transmission-Related General Plant (Line*	48,330,238	*Page 207.99g*	
14	*= Revised Numerator (Line 12 + Line 13)*	812,718,764		
15	Total Plant in Service	819,159,493	Page 207.104g	Includes Benn-Searsburg line
16	Percent Allocation (Line 14 / Line 15)	99.2137%		

Sheet: Worksheet 6 PTF Revenue Requirements

Affiliated Company Wages and Salaries

Worksheet 6 of 8

▨ 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 1	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

			TOTAL	
Particip	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	32.(g); [332.1(g) for HWP]		40,290
	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**			12,657
	115 kV Wyman 164-167 lines			4,750
	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**			252,852
	Comerford 115 kV Substation			44,183
	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]		610,162
	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)		60,641
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
		Total =	0	1,025,535

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 12, 2011
Revenue Requirements for (year):	**Calendar Yr 2010** $ 92,886,147
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)	92,886,237	(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)	(90)	(i)
Sub Total - Sum (A through I) - J + K + (L through O)		0	(e)=(a)-(b)+(c)+(d)	92,886,147	(j)

Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:	92,886,147	(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	92,886,147	(l)=(k)+(b)+(g)-(h)

VT TRANSCO
Annual Revenue Requirements of PTF Facilities
for costs in 2010

PTF Revenue Requirements
Worksheet 1 of 8

▨ Shading denotes an input

Line N	I. INVESTMENT BASE	Attachment F Reference Section:	Total	Reference
1	Transmission Plant	(A)(1)(a)	552,481,549	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	34,931,936	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	1,347,187	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		588,760,672	
5	Accumulated Depreciation	(A)(1)(d)	77,527,610	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	32,794,252	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)		478,438,810	
10	Prepayments	(A)(1)(h)	404,418	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	5,193,930	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	1,220,924	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		485,258,082	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	62,451,357	Worksheet 2
	Investment Return and Income Taxes Post-2003 Incremer		2,039,279	Worksheet adder
15	Depreciation Expense	(B)	10,730,256	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)	7,175,620	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	722,332	*Worksheet 4, line 23 column 5*
20	Operation & Maintenance Expense	(G)	5,633,359	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	4,134,034	Worksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Charg	(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)	374,627	Gross Revenue Tax
27	Revenue for ST Trans. Service Under NEPOOL	(N)	(359,276)	Schedule 8 TOUT Revenues
28	Transmission Rents Received from Electric Prop	(O)	(15,442)	Rev Rent 4000-454122
29	Total Revenue Requirements (Line 14 thru 28)		92,886,147	

VT TRANSCO

Annual Revenue Requirements
for costs in 2010

▨ Shading denotes an input

		CAPITALIZATION 12/31/10		CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTIOI
LONG-TERM DEBT	$	329,093,000	Page 112.24c	46.59%	5.51%	2.57%	
PREFERRED STOCK		0		0.00%	0.00%	0.00%	0.00%
COMMON EQUITY		377,299,526	Page 112.16c	53.42%	11.64%	6.22%	6.22%
TOTAL INVESTMEN	$	706,392,526		100.01%		8.79%	6.22%

Cost of Capital Rate=

(a) Weighted Cost o = 0.0879

				PTF Inv.		Eq. AFUDC						
(b) Federal Income ˙	=	R.O.E. +	(	(Tax Credit	+	of Depre	) /	PTF Inv. Base)	x	Federal Income Tax Rate	)	
	(								-	Federal Income Tax Rate	)	
	=	0.0622	+	0	+	0	`	485,258,082	) x	0.34	)	
	(	1							-	0.34	)	
	=	0.0320424										

				PTF Inv.		Eq. AFUDC						
(c) State Income Ta:	=	R.O.E. +	(	(Tax Credit	+	of Depre	) /	PTF Inv. Base)	+	Federal Income Tax	)*	State Income Ta:
	(	1							-	State Income Tax Rate	)	
	=	0.0622	+	0	+	0	) /	485,258,082	) +	0.0320424	)*	0.085
	(	1							-	0.085	)	
	=	0.0087548										

(a)+(b)+(c) **Cost of** = 0.1286972

		(PTF)	
INVESTMENT BASE	$	485,258,082	From Worksheet 1
x Cost of Capital Rate		0.1286972	
= Investment Return and		62,451,357	To Worksheet 1

VT TRANSCO

Annual Revenue Requirements
for costs in 2010

▨ Shading denotes an input

		CAPITALIZATION 12/31/10	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	329,093,000	46.59%		0.00%	
PREFERRED STOCK		0	0.00%		0.00%	0.00%
COMMON EQUITY		377,299,526	53.42%	1.00%	0.53%	0.53%
TOTAL INVESTMENT RE	$	706,392,526	100.01%		0.53%	0.53%

Cost of Capital Rate=

(a) Weighted Cost of Cap = 0.0053

(b) Federal Income Tax = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Depre) / PTF Inv. Base) x Federal Income Tax Rate)
(- Federal Income Tax Rate)

= 0.0053 + 0 + 0 ` 232,362,016) x 0.34)
(1 - 0.34)

= 0.0027303

(c) State Income Tax = R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Depre) / PTF Inv. Base) + Federal Income Tax)* State Income Tax Rate
(1 - State Income Tax Rate)

= 0.0053 + 0 + 0) / 232,362,016) + 0.0027303)* 0.085
(1 - 0.085)

= 0.0007460

(a)+(b)+(c) **Cost of Capi** = 0.0087763

	(PTF)	
Post-2003 INVESTMENT BASE		
PTF Transmission Plant	282,438,500	
less Accum Depreciation Rese	33,178,608	
less Accum Deferred Taxes	(16,897,876)	
Post-2003 INVESTMENT BAS	232,362,016	
INVESTMENT BASE $	232,362,016	From Worksheet Post-2003
x Cost of Capital Rate	0.0087763	
= Investment Return and Incoı	2,039,279	To Worksheet 1

VT TRANSCO
Annual Revenue Requirements of post-2003 PTF Incremental Return
for costs in 2010

RNS Rate

Worksheet 1b of 8

Line No.		(1) Total Transmission	(2) Post-2003 [1] PTF	Total Transmission Reference
	I. INVESTMENT BASE			
1	Transmission Plant	764,388,526	282,438,500	Internal Plant Accounting
2	Accumulated Depreciation	89,794,230	33,178,608	Worksheet 3, line 5 column 1 + line 5A column 1
3	Accumulated Deferred Income Taxes	(45,732,229)	(16,897,876)	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)	628,862,067	232,362,016	
	II. INCREMENTAL RETURN			
6	Incremental Revenue Requirements		2,039,279	Worksheet 2a
7	PTF Transmission Plant Allocation Factor		36.9496%	

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

.ine 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)
	Transmission Plant						
1	Transmission Plant	764,388,526		764,388,526		552,481,549	Line 1, Worksheet 5
2	General Plant	48,330,238	100.0000% (a	48,330,238	72.2776%	34,931,936	Page 207.99g
3	Total (line 1+2)			812,718,764		587,413,485	
4	Transmission Plant Held for Future	1,863,906		1,863,906	72.2776%	1,347,187	Page 214.47d
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	89,794,230		89,794,230	72.2776%	64,901,114	Page 219.25b
6	General Plant Accum.Depreciation	17,469,445	100.0000% (a	17,469,445	72.2776%	12,626,496	Page 219.27b
7	Total (line 5+6)			107,263,675		77,527,610	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281	(45,732,229)	99.2137% (c	(45,372,636)	72.2776%	(32,794,252)	Page 113.63d
9	Accumulated Deferred Taxes (190	0	99.2137% (c	0	72.2776%	0	Page 111.68d
10	Total (line 8+9)			(45,372,636)		(32,794,252)	
11	Transmission loss on Reacquired D	0	99.2137% (c	0	72.2776%	0	Page 111.81d
	Other Regulatory Assets						
12	FAS 106	0	100.0000% (a	0	72.2776%	0	Page 232.30e
13	FAS 109	0	99.2137% (c	0	72.2776%	0	Page 232.21&23e
14	Other Regulatory Liabilities (254.D	0	99.2137% (c	0	72.2776%	0	Page 278.1e
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments	559,534	100.0000% (a	559,534	72.2776%	404,418	Page 111.57c
17	Transmission Materials and Suppli	7,186,086		7,186,086	72.2776%	5,193,930	Page 227.8c
18	Cash Working Capital						
19	Operation & Maintenance Expense					5,633,359	Worksheet 1, Line 20
20	Administrative & General Expense					4,134,034	Worksheet 1, Line 21
21	Transmission Support Expense					0	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					9,767,393	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					1,220,924	

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

VT TRANSCO

Sheet: Worksheet 4

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)
	Depreciation Expense							
1	Transmission Depreciation	11,768,120			11,768,120	72.2776%	8,505,715	Page 336.7b
2	General Depreciation	3,077,774	100.0000%	(a)	3,077,774	72.2776%	2,224,541	Page 336.9b
3	Total (line 1+2)				14,845,894		10,730,256	
4	Amortization of Loss on Reacquired I	0	99.2137%	(c)	0	72.2776%	0	Page 117.64c
5	Amortization of Investment Tax Credits		99.2137%	(c)	0	72.2776%	0	Page 266.8f
	Property Taxes *							
6	Transmission Property Taxes	9,927,862	99.2137%	(c)	9,927,862	72.2776%	7,175,620	Page 262-263 FN.1-2
7	General Property Taxes				0	72.2776%	0	Page 262-263 FN.1-2
8	Total (line 6+7)				9,927,862		7,175,620	
	Transmission Operation and Maintenance							
9	Operation and Maintenance	10,604,067			10,604,067	72.2776%	7,664,365	Page 321.112b
10	Transmission of Electricity by Others	586,968			586,968	72.2776%	424,246	Page 321.96b
11	Load Dispatching - #561.1-561.4	2,178,858			2,178,858	72.2776%	1,574,826	Page 321.84 - 88b
12	**Station Expenses & Rents - #562 / #567	44,183			44,183	72.2776%	31,934	Page 321.93b & .98b
13	O&M less lines 10, 11 & 12	7,794,058			7,794,058	`	5,633,359	
	Transmission Administrative and General							
14	Administrative and General	5,727,347						Page 323.197b
15	*less Property Insurance (#924)*	*671,643*						*Page 323.185b*
16	*less Regulatory Commission Expenses (#928)*	*258,720*						*Page 323.189b*
17	*less General Advertising Expense (#930.1)*	*47,056*						*Page 323.191b*
18	Subtotal [line 14 minus (15 thru 17)]	4,749,928	100.0000%	(a)	4,749,928	72.2776%	3,433,134	
19	*PLUS Property Insurance alloc. using Plant Allocatio*	*671,643*	99.2137%	*(c)*	666,362	72.2776%	481,630	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	*258,720*	99.2137%	*(c)*	256,686	72.2776%	185,526	
21	*PLUS Trans. Related General Advertising Expense*	*47,056*	99.2137%	*(c)*	46,686	72.2776%	33,744	
22	Total A&G [line 18 plus (19 thru 21)]	*5,727,347*			*5,719,662*		*4,134,034*	
23	*Payroll Tax Expense*	*999,386*	100.0000%	*(a)*	*999,386*	72.2776%	*722,332*	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	9,039	
FICA	948,258	
Medicare	0	
CT Unemployment	0	
MA Unemployment	0	
MA Universal Health	0	
VT Unemployment	42,089	
NH Unemployment	0	
Total	999,386	*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 Fact	**VT TRANSCO**		
1	PTF Transmission Investment	552,481,549	NEPOOL Catalog	
2	Total Transmission Investment	764,388,526	Page 207.58g	Includes Benn-Searsburg line
3	Percent Allocation (Line 1/Line 2)	72.2776%		
	Transmission Wages and Salaries Allocation Factor			
4	Direct Transmission Wages and Salaries	5,158,883	Page 354.21b	
5	Affiliated Company Transmission Wages and S	0	Worksheet 6 & 6a of 8	
6	Total Transmission Wages and Salaries (Li	5,158,883		
7	Total Wages and Salaries	9,408,987	Page 354.28b	
8	Administrative and General Wages and Salarie	4,250,104	Page 354.27b	
9	Affiliated Company Wages and Salaries less A	0	Worksheet 6 & 6a of 8	
10	Total Wages and Salaries net of A&G (Line	5,158,883		
11	Percent Allocation (Line 6/Line 10)	100.0000%		`
	Plant Allocation Factor			
12	Total Transmission Investment	764,388,526	Page 207.58g	Includes Benn-Searsburg line
13	*plus Transmission-Related General Plant (Line*	48,330,238	*Page 207.99g*	
14	*= Revised Numerator (Line 12 + Line 13)*	812,718,764		
15	Total Plant in Service	819,159,493	Page 207.104g	Includes Benn-Searsburg line
16	Percent Allocation (Line 14 / Line 15)	99.2137%		

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 1	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)

VERMONT TRANSCO LLC
Forecasted Transmission Revenue Requirements of PTF Facilities
Calendar Year 2011

	Estimated Additional PTF In Service for 2011
Southern Loop	8,500,000
West Rutland Upgrade	2,100,000
Reactor Additions	9,200,000
Other	1,000,000
Total	20,800,000

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VT TRANSCO

Forecasted Transmission Revenue Requirements of PTF Facilities

POST-1996

▨ Shading denotes an input

Line No.			Period	Attachment F Reference Section:	VELCO	Reference
	I.	FORECASTED TRANSMISSION REVENUE REQUIREMENTS				
1		Forecasted Transmission Plant Additions	2011	Appendix C	$20,800,000	
2		Carrying Charge Factor		Appendix C	16.44%	
3		Total Forecasted Revenue Requirements (Lines 1*2)			$3,420,235	
	II.	CARRYING CHARGE FACTOR				
4		Investment Return and Income Taxes		(A)	$62,451,357	Summary, line 14
5		Depreciation Expense		(B)	$10,730,256	Summary, line 15
6		Amortization of Loss on Reacquired Debt		(C)	$0	Summary, line 16
7		Investment Tax Credit		(D)	$0	Summary, line 17
8		Property Tax Expense		(E)	$7,175,620	Summary, line 18
9		Payroll Tax Expense		(F)	$722,332	Summary, line 19
10		Operation & Maintenance Expense		(G)	$5,633,359	Summary, line 20
11		Administrative & General Expense		(H)	$4,134,034	Summary, line 21
12		Total Expenses (Lines 4 thru 11)			$90,846,958	
13		PTF Transmission Plant		(A)(1)(a)	$552,481,549	Summary, line 1
14		Carrying Charge Factor (Lines 12/13)			16.44%	

VERMONT TRANSCO LLC
ROLLFORWARD PTF INVESTMENT

		Investment as of 12/31/09	Additions	Retirements	Adjustments	Investment as of 12/31/10
SUBSTATIONS						
20S	Highgate Converter	35,313.29				35,313.29
28S	Charlotte Substation	812,983.47	28,504.06		(82,123.40)	759,364.12
30S	West Rutland	15,252,637.08	499,799.37	4,820.47		15,747,615.98
40S	Vermont Yankee Substation	7,945,401.55	4,852,864.87	1,140,624.25		11,657,642.17
44S	Vergennes Substation	4,438,152.53	9,951.04			4,448,103.57
45S	Ferrisburg	1,375,714.21			(253,044.80)	1,122,669.41
52S	Granite	85,880,551.30	743,952.69	865,884.67	(764,982.40)	84,993,636.92
53S	Shelburne Substation	824,431.77	83,921.59		(97,682.83)	810,670.53
54S	Coolidge 115/345 Kv	9,114,851.22	15,457,122.93	824,709.64		23,747,264.51
61S	St Albans	44,737.83				44,737.83
62S	Essex	22,433,150.03				22,433,150.03
63S	Barre	208,088.30	9,993.59	1,612.78	(1,758.29)	214,710.82
64S	East Ave Substation	3,925,087.46	251,690.70		20,012.47	4,196,790.63
65S	Middlesex Substation	1,508,152.25				1,508,152.25
66S	St Johnsbury	1,389,037.05			2,047.71	1,391,084.76
68S	Irasburg	829,474.36			53,989.35	883,463.71
69S	Queen City Substation	4,813,632.15	23,015.39			4,836,647.54
70S	Ascutney	543,896.66	46,741.57	2,575.39		588,062.83
71S	North Rutland	1,155,226.71		60,096.47	6,372.19	1,101,502.43
72S	Middlebury	925,562.67		3,237.04	10,642.47	932,968.10
73S	Bennington	2,764,416.97	42,261.90	768.72	(2,227.47)	2,803,682.68
74S	New Haven	28,963,869.15	1,380,769.07			30,344,638.23
75S	Chelsea	147,139.20			9,393.06	156,532.26
76S	Blissville	10,588,949.00		4,553.04	101,723.00	10,686,118.96
77S	Hartford	3,002,467.63		8,541.98	69,173.23	3,063,098.88
79S	Newfane	0.00	11,006,534.48		(2,161.26)	11,004,373.22
80S	Georgia	1,502,190.17	65,815.64	18,811.87		1,549,193.94
81S	St Albans	1,125,855.02				1,125,855.02
82S	Sandbar	8,659,446.91	122,430.35	23,255.12		8,758,622.14
83S	Williston	5,381,700.75	11,706.67	2,352.83		5,391,054.59
85S	Vernon Substation	0.00	41,847,857.86			41,847,857.86
86S	Lyndonville Substation	0.00	6,395,148.93		8,442.27	6,403,591.20
87S	Line Kiln Substation	0.00	7,481,466.90			7,481,466.90
89S	Cold River	2,386,736.50		1,292,792.50	56,112.70	1,150,056.70
91S	Berlin	1,145,982.92			25,310.09	1,171,293.01
93S	Highgate	8,338,657.59				8,338,657.59
95S	South Hero	384,864.41				384,864.41
98S	GMP Taft Corner	5,103,737.63	58,145.86		(53,601.75)	5,108,281.74
101S	Duxbury Switching Station	531,512.20	43,441.64			574,953.84
173S	Plattsburgh PAR					
		243,483,607.93	90,463,137.09	4,254,636.77	(894,363.66)	328,797,744.59
LINES						
	Bennington - Searsburg	1,456,023.02				1,456,023.02
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				360,709.51
14L	Ascutney-NEES	90,789.76				90,789.76
17L	Ascutney-PSNH	69,342.11				69,342.11
18L	Vernon-Keene Tie	45,122.59	160,429.11			205,551.70
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				2,377,018.31
22L	Lake Champlain-Essex	4,680,411.39	8,362.22	6,541.79		4,682,231.82
23L	Essex-Middlebury	4,241,379.28				4,241,379.28
24L	Essex-Barre	1,615,431.78	8,362.22	788.73		1,623,005.27
25L	Essex-Burlington	16,518,819.54	537,544.46			17,056,364.00
26L	Barre-Wilder	3,320,866.69				3,320,866.69
27L	Essex-Georgia	1,393,426.71				1,393,426.71
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	1,901,903.62	16,724.42	1,558.08		1,917,069.96
33L	Queen City Tap	2,003,227.09				2,003,227.09
35L	WEST RUTL MIDDLEBURY 345K	49,164,553.32	415,756.28			49,580,309.60
37L	Vernon-Scobie Tie	437,797.23	181,789.44			619,586.67
38L	Vernon-Northfield Tie	385,133.00	179,863.97			564,996.97
39L	St. Johnsbury-Irasburg	2,933,682.27	540,152.14			3,473,834.41
40L	Vernon-Coolidge	7,535,584.41	1,918,337.72	18,049.40		9,435,872.73
41L	Coolidge-West Rutland	8,487,201.11		23,189.53		8,464,011.58
42L	Richford-New Highgate 120	1,388,381.56	170,489.44	2,125.00	(850.00)	1,555,896.00
44L	NEWPORT-RICHFORD(120kV)	2,316,608.50				2,316,608.50
47L	Irasb to Moshers Tap 115k	4,553,701.20				4,553,701.20
48L	New Haven to Queen City	61,074,953.52	138,751.17			61,213,704.69
49L	Duxbury - Stowe	1,521,069.46	112,261.99			1,633,331.45
51L	Newfane - Vernon	0.00	35,115,513.52			35,115,513.52
52L	Newfane - Coolidge	0.00	52,881,036.79			52,881,036.79
53L	Vernon - VY	0.00	110,693.08			110,693.08
54L	Vernon - Vernon	0.00	1,421,294.98			1,421,294.98
L34	West Rutland - Whitehall	953,507.31				953,507.31
		193,120,652.70	93,917,362.95	52,252.53	(850.00)	286,984,913.12
	TOTAL PTF Facilities	436,604,260.63	184,380,500.04	4,306,889.30	(895,213.66)	615,782,657.71

HIGHGATE JOINT OWNERS

	Revenue Requirements Year End 2010
City of Burlington Electric Department	233,673.00
Central Vermont Public Service Corporation	3,357,726.00
Vermont Marble	15,974.00
Green Mountain Power Corporation	1,472,293.00
Vermont Public Power Supply Authority	236,854.00
Johnson	12,549.00
	5,329,069.00

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

TOTAL

Submitted on: May 17, 2011 RTO ROE filing

Revenue Requirements for (year): **Calendar Yr 2010** $ 5,329,069

Customer:

Customer's NABs Number:

Name of Participant responsible for customer's billing:

DUNs number of Participant responsible for customer's billing:

		Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	=	5,329,069	(a)		(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)		0	(d)		(i)
Sub Total - Sum (A through I) - J + K + (L through O)		5,329,069	(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:	5,329,069	(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: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)	5,329,069	(l)=(k)+(b)+(g)-(h)

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 17, 2011 RTO ROE filing

Revenue Requirements for (year): **Calendar Yr 2010** $ 233,673

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:

		Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	=	233,673	(a)		(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)		0	(d)		(i)
Sub Total - Sum (A through I) - J + K + (L through O)		233,673	(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: 233,673 (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: 233,673 (l)=(k)+(b)+(g)-(h)

(for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)

Sheet: Worksheet 1

Annual Revenue Requirements of PTF Facilities
for costs in 2010

PTF Revenue Requirements
Worksheet 1 of 8

🟨 Shading denotes an input

Line N		Attachment F Reference Section:	Total	Reference
I.	INVESTMENT BASE			
1	Transmission Plant	(A)(1)(a)	2,359,520	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)		2,359,520	
5	Accumulated Depreciation	(A)(1)(d)	1,388,194	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)		971,326	
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)	6,437	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		977,763	
II.	REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	80,079	Worksheet 2
15	Depreciation Expense	(B)	62,745	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)	39,354	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	0	*Worksheet 4, line 23 column 5*
20	Operation & Maintenance Expense	(G)	48,193	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	3,302	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 Ta	(N)		
28	Transmission Rents Received from Electric Propert	(O)		
29	Total Revenue Requirements (Line 14 thru 28)		233,673	

Annual Revenue Requirements
for costs in 2010

▨ Shading denotes an input

		CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTIO
LONG-TERM DEBT	$	69,618,076	57.17%	5.59%	3.20%	
PREFERRED STOCK		0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY		52,156,707	42.84%	11.64%	4.99%	4.99%
TOTAL INVESTMENT	$	121,774,782	100.01%		8.19%	4.99%

Cost of Capital Rate=

(a) Weighted Cost of (	=	0.0819											
				PTF Inv.		Eq. AFUDC							
(b) Federal Income Ta	=	R.O.E. +	(	(Tax Credit	+	of Deprec)	/	PTF Inv. Base)		x	Federal Income Tax Rate	)	
	(									-	Federal Income Tax Rate	)	
	=	0.0499	+	0	+	0	`	977,763	)	x	0	)	
	(	1								-	0	)	
	=	0.0000000											
				PTF Inv.		Eq. AFUDC							
(c) State Income Tax	=	R.O.E. +	(	(Tax Credit	+	of Deprec)	/	PTF Inv. Base)		+	Federal Income Tax	)*	State Income Tax Rate
	(	1								-	State Income Tax Rate	)	
	=	0.0499	+	0	+	0)	/	977,763	)	+	0.0000000	)*	0
	(	1								-	0	)	
	=	0.0000000											
(a)+(b)+(c) **Cost of C**	=	0.0819000											

		(PTF)	
INVESTMENT BASE	$	977,763	From Worksheet 1
x Cost of Capital Rate		0.0819000	
= Investment Return and In		80,079	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 (
	Transmission Plant						
1	Transmission Plant	2,674,811		2,674,811		2,359,520	Line 1, Workshe
2	General Plant	9,948,188	0.0000% (a	0	88.2126%	0	Page 207.90g
3	Total (line 1+2)	12,622,999		2,674,811		2,359,520	
4	Transmission Plant Held for Future Use	0		0	88.2126%	0	Page 214.47d
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	1,573,691		1,573,691	88.2126%	1,388,194	Page 219.25b
6	General Plant Accum.Depreciation	6,013,352	0.0000% (a	0	88.2126%	0	Page 219.28b
7	Total (line 5+6)	7,587,044		1,573,691		1,388,194	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	0	2.1069% (c	0	88.2126%	0	Page 113.(57-6
9	Accumulated Deferred Taxes (190)	0	2.1069% (c	0	88.2126%	0	Page 111.82c
10	Total (line 8+9)			0		0	
11	Transmission loss on Reacquired Debt	0	2.1069% (c	0	88.2126%	0	Page 111.81d
	Other Regulatory Assets						
12	FAS 106	0	0.0000% (a	0	88.2126%	0	Page 232.30e
13	FAS 109	0	2.1069% (c	0	88.2126%	0	Page 232.21&2
14	Other Regulatory Liabilities (254.DK)	0	2.1069% (c	0	88.2126%	0	Page 278.1e
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments	0	0.0000% (a	0	88.2126%	0	Page 111.57c
17	Transmission Materials and Supplies	0		0	88.2126%	0	Page 227.8c
18	Cash Working Capital						
19	Operation & Maintenance Expense					48,193	Worksheet 1, Li
20	Administrative & General Expense					3,302	Worksheet 1, Li
21	Transmission Support Expense					0	Worksheet 1, Li
22	Subtotal (line 19+20+21)					51,495	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					6,437	

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

Sheet: Worksheet 4

▨ Shading denotes an input

ine No.		(1) Total	(2) for costs in 2010 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	Transmission Depreciation	71,129		71,129	88.2126%	62,745	Page 336.7b
2	General Depreciation	253,104	0.0000% (a)	0	88.2126%	0	Page 336.10b
3	Total (line 1+2)	324,234		71,129		62,745	
4	Amortization of Loss on Reacquired Debt	0	2.1069% (c)	0	88.2126%	0	Page 117.64c
5	Amortization of Investment Tax Credits	0	2.1069% (c)	0	88.2126%	0	Page 266.8f
	Property Taxes *						
6	Transmission Property Taxes	53,006	2.1069% (c)	1,117	88.2126%	985	Page 262-263 FN.1-2
7	General Property Taxes	2,064,474	2.1069%	43,496	88.2126%	38,369	Page 262-263 FN.1-2
8	Total (line 6+7)	2,117,480		44,613		39,354	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	3,539,605		3,539,605	88.2126%	3,122,378	Page 321.112b
10	Transmission of Electricity by Others - #565	3,484,973		3,484,973	88.2126%	3,074,185	Page 321.96b
11	Load Dispatching - #561	0		0	88.2126%	0	Page 321.84b
12	**Station Expenses & Rents - #562 / #567	0		0	88.2126%	0	Page 321.85b & .90b
13	O&M less lines 10, 11 & 12	54,632		54,632	`	48,193	
	Transmission Administrative and General						
14	Administrative and General	2,362,153					Page 323.197b
15	*less Property Insurance (#924)*	*153,863*					*Page 323.185b*
16	*less Regulatory Commission Expenses (#928)*	*23,766*					*Page 323.189b*
17	*less General Advertising Expense (#930.1)*	*0*					*Page 323.191b*
18	Subtotal [line 14 minus (15 thru 17)]	2,184,525	0.0000% (a)	0	88.2126%	0	
19	*PLUS Property Insurance alloc. using Plant Allocation*	*153,863*	2.1069% *(c)*	3,242	88.2126%	2,860	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	*23,766*	2.1069% *(c)*	501	88.2126%	442	
21	*PLUS Trans. Related General Advertising Expense*	*0*	2.1069% *(c)*	0	88.2126%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*2,362,153*		*3,743*		*3,302*	
23	*Payroll Tax Expense*	*654,685*	0.0000% *(a)*	*0*	88.2126%	*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	*529,761*	
Medicare	*124,924*	
CT Unemployment		
MA Unemployment		
MA Universal Health		
VT Unemployment	*0*	
NH Unemployment	*0*	
Total	654,685	*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	2,359,520	NEPOOL Catalog
2	Total Transmission Investment	2,674,811	Page 207.58g
3	Percent Allocation (Line 1/Line 2)	88.2126%	
	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	0	
7	Total Wages and Salaries	7,334,642	Page 354.28b
8	Administrative and General Wages and Salaries	1,380,128	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)	5,954,515	
11	Percent Allocation (Line 6/Line 10)	0.0000%	
	Plant Allocation Factor		
12	Total Transmission Investment	2,674,811	Page 207.58g
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3*	19,158	*Page 207.99g*
14	*= Revised Numerator (Line 12 + Line 13)*	2,693,970	
15	Total Plant in Service	127,866,085	Page 207.104g
16	Percent Allocation (Line 14 / Line 15)	2.1069%	

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		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 exp with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23

			TOTAL	
Particip	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 3	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 li	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 17, 2011 RTO ROE filing

Revenue Requirements for (year): **Calendar Yr 2010** $ 3,357,726

Customer:

Customer's NABs Number:

Name of Participant responsible for customer's billing:

DUNs number of Participant responsible for customer's billing:

		Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	=	3,357,726	(a)	`	(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)		0	(d)		(i)
Sub Total - Sum (A through I) - J + K + (L through O)		3,357,726	(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:	3,357,726	(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: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)	3,357,726	(l)=(k)+(b)+(g)-(h)

Annual Revenue Requirements of PTF Facilities
for costs in 2010

🟨 Shading denotes an input

Line N		Attachment F Reference Section:	Total	Reference
	I. INVESTMENT BASE			
1	Transmission Plant	(A)(1)(a)	14,627,005	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	467,093	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	1,057	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		15,095,155	
5	Accumulated Depreciation	(A)(1)(d)	6,098,306	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	2,007,181	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)	110,552	Worksheet 3, line 15 column 5
9	Net Investment (Line 4-5-6 -24942312		7,100,220	
10	Prepayments	(A)(1)(h)	237,102	Worksheet 3, line 16 column 5
11	Materials & Supplies	(A)(1)(i)	288,945	Worksheet 3, line 17 column 5
12	Cash Working Capital	(A)(1)(j)	201,186	Worksheet 3, line 24 column 5
13	Total Investment Base (Line 9+10+11+12)		7,827,453	
	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	1,067,029	Worksheet 2
15	Depreciation Expense	(B)	368,240	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)	(6,293)	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	286,253	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	33,008	*Worksheet 4, line 23 column 5*
20	Operation & Maintenance Expense	(G)	1,121,438	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	488,051	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 Ta	(N)		
28	Transmission Rents Received from Electric Propert	(O)		
29	Total Revenue Requirements (Line 14 thru 28)		3,357,726	

Annual Revenue Requirements
for costs in 2010

▨ Shading denotes an input

		CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	208,300,000	42.59%	6.20%	2.64%	
PREFERRED STOCK		8,053,800	1.65%	4.90%	0.08%	0.08%
COMMON EQUITY		272,729,010	55.77%	11.64%	6.49%	6.49%
TOTAL INVESTMENT	$	489,082,810	100.01%		9.21%	6.57%

Cost of Capital Rate=

(a) Weighted Cost of (### 9.21%

PTF Inv. heet 3, line 16 column 5

(b) Federal Income Ta = R.O.E. + ((Tax Credit + Workshee) / PTF Inv. Base) x Federal Income Tax Rate)
(- Federal Income Tax Rate)

= 0.0657 + (6,293) + 0 ` 7,827,453) x 0.35)
(1 - 0.35)

= 0.0349440

PTF Inv. Eq. AFUDC

(c) State Income Tax = R.O.E. + ((Tax Credit + of Deprec) / PTF Inv. Base) + Federal Income Tax)* State Income Tax Rate
1 - State Income Tax Rate)

= 0.0657 + (6,293) + 0) / 7,827,453) + 0.0349440)* 0.085
(1 - 0.085)

= 0.0092748

(a)+(b)+(c) **Cost of C** = 0.1363188

		(PTF)	
INVESTMENT BASE	$	7,827,453	From Worksheet 1
x Cost of Capital Rate		0.1363188	
= Investment Return and In		1,067,029	To Worksheet 1

Sheet: Worksheet 3

▨ Shading denotes an input

ine 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)
	Transmission Plant						
1	Transmission Plant	75,253,675		75,253,675		14,627,005	Line 2, Worksheet 5
2	General Plant	38,990,297	6.1634% (a	2,403,126	19.4369%	467,093	Page 207.99g
3	Total (line 1+2)			77,656,801		15,094,098	
4	Transmission Plant Held for Future Use	42,819	12.6952% (c	5,436	19.4369%	1,057	Page 214.2d
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	30,282,332		30,282,332	19.4369%	5,885,947	Page 219.25b
6	General Plant Accum.Depreciation	17,726,550	6.1634% (a	1,092,557	19.4369%	212,359	Page 219.28b
7	Total (line 5+6)			31,374,889		6,098,306	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	106,285,267	12.6952% (c	13,493,127	19.4369%	2,622,646	Page 113.(62-64)d
9	Accumulated Deferred Taxes (190)	(24,942,312)	12.6952% (c	(3,166,476)	19.4369%	(615,465)	Page 111.82c
10	Total (line 8+9)			10,326,651		2,007,181	
11	Transmission loss on Reacquired Debt	0	12.6952% (c	0	19.4369%	0	Page 111.81d
	Other Regulatory Assets						
12	FAS 106	0	6.1634% (a	0	19.4369%	0	Page 232.30e
13	FAS 109	4,480,226	12.6952% (c	568,774	19.4369%	110,552	Page 232.21&23e
14	Other Regulatory Liabilities (254.DK)	0	12.6952% (c	0	19.4369%	0	Page 278.1e
15	Total (line 12+13+14	4,480,226		568,774		110,552	
16	Transmission Prepayments	19,791,962	6.1634% (a	1,219,857	19.4369%	237,102	Page 111.57c
17	Transmission Materials and Supplies	1,486,582		1,486,582	19.4369%	288,945	Page 227.8c
18	Cash Working Capital						
19	Operation & Maintenance Expense					1,121,438	Worksheet 1, Line 20
20	Administrative & General Expense					488,051	Worksheet 1, Line 21
21	Transmission Support Expense					0	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					1,609,489	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					201,186	

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

Sheet: Worksheet 4

Shading denotes an input

ine No.		(1) Total	(2) for costs in 2005 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	Transmission Depreciation	1,693,612		1,693,612	19.4369%	329,186	Page 336.7b
2	General Depreciation	3,260,008	6.1634% (a)	200,927	19.4369%	39,054	Page 336.10b
3	Total (line 1+2)			1,894,539		368,240	
4	Amortization of Loss on Reacquired Debt	0		0	19.4369%	0	Page 117.64c
5	Amortization of Investment Tax Credits	255,021	12.6952% (c)	32,375	19.4369%	6,293	Page 266.8f
	Property Taxes *						
6	Transmission Property Taxes	11,600,679	12.6952% (c)	1,472,729	19.4369%	286,253	Page 262-263 FN.1-2
7	General Property Taxes	0	6.1634%	0	19.4369%	0	Page 262-263 FN.1-2
8	Total (line 6+7)			1,472,729		286,253	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	24,731,069		24,731,069 W	19.4369%	4,806,953	Page 321.112b
10	Transmission of Electricity by Others - #565	18,897,468		18,897,468 W	19.4369%	3,673,082	Page 321.96b
11	Load Dispatching - #561	63,968		63,968 W	19.4369%	12,433	Page 321.84b
12	**Station Expenses & Rents - #562 / #567	0		0	19.4369%	0	Page 321.85b & .90b
13	O&M less lines 10, 11 & 12	5,769,633		5,769,633 `		1,121,438	
	Transmission Administrative and General						
14	Administrative and General	38,846,112					Page 323.197b
15	*less Property Insurance (#924)*	*867,349*					*Page 323.185b*
16	*less Regulatory Commission Expenses (#928)*	*919,448*					*Page 323.189b*
17	*less General Advertising Expense (#930.1)*	*0*					*Page 323.191b*
18	Subtotal [line 14 minus (15 thru 17)]	37,059,315	6.1634% (a)	2,284,112	19.4369%	443,961	
19	*PLUS Property Insurance alloc. using Plant Allocatior*	*867,349*	12.6952% *(c)*	110,112	19.4369%	21,402	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	*919,448*	12.6952% *(c)*	116,726	19.4369%	22,688	
21	*PLUS Trans. Related General Advertising Expense*	*0*	12.6952% *(c)*	0	19.4369%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*38,846,112*		*2,510,950*		*488,051*	
23	*Payroll Tax Expense*	*2,755,319*	6.1634% *(a)*	*169,821*	19.4369%	*33,008*	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	*30,213*	
FICA	*2,611,145*	
Medicare	*0*	
CT Unemployment		
MA Unemployment		
MA Universal Health		
VT Unemployment	*113,961*	
NH Unemployment	*0*	
Total	2,755,319	*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		
1	PTF Transmission Investment	14,627,005	NEPOOL Catalog
2	Total Transmission Investment	75,253,675	Page 207.58g
		89,880,680	
3	Percent Allocation (Line 1/Line 2)	19.4369%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	1,453,184	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	1,453,184	
	#		
7	Total Wages and Salaries	36,262,829	Page 354.28b
8	Administrative and General Wages and Salaries	12,685,175	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)	23,577,654	
11	Percent Allocation (Line 6/Line 10)	6.1634%	`
	Plant Allocation Factor		
12	Total Transmission Investment	75,253,675	Page 207.58g
13	*plus Transmission-Related General Pla* #	2,403,126	Worksheet 3, line 2 column 3
14	*= Revised Numerator (Line 12 + Line 13)*	77,656,801	
	#		
15	Total Plant in Service	611,703,228	Page 207.104g
16	Percent Allocation (Line 14 / Line 15)	12.6952%	

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			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 exp
with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23

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	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 3	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 li	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)

Vermont Electric Cooperative, Inc.
2010 Highgate Transmission Facilities Revenue Requirements

	Rental Fee Form 1 Column (l)	Base Rental Form 1 Column (m)	Total Revenues Form 1 Column (n)
Vermont Electric Cooperative			
VEC VT Special Contract 808 (Former Rate Sch FERC No. 8)			
Form 1 Line 9	14,119	1,854	
2010 Vermont DPS Electric Utility Annual Report, Schedule E-3, line 68			15,974

2010 Highgate Transmission Facilities Revenues	**15,974**

Calculation of VEC's 2010 Highgate Transmission Facilities Revenue Requirements

Rental Fee = Recovery of Non-Project Manager Invoiced Costs, including	14,119
(A) Return, (B) Depreciation, and (H) Non-Project Manager A&G	
(C) and (D) Amortization and Credits	
Base Rental = (E) and (F) Taxes, and (G) O&M, and (H) Project Manager A&G	1,854
(I) Integrated Facilities Charges	
less (J) Transmission Support Revenues	(15,974) *
(K) Support Expense	
(L) Transmission Expense from Generator	
(M) Related Taxes and Fees	
less (N) Short-Term OATT Revenues	
less (O) Transmission Support Revenues	
VEC's 2010 Highgate Transmission Facilities Revenue Requirements	**0**

* Paid by Vermont Marble Power Division

Vermont Electric Cooperative
Year Ended December 31, 2010

OPERATION AND MAINTENANCE EXPENSES (Continued)

	PARTICULARS (a)				Amount for year (b)	Increase or decrease from preceding year (c)
7	**CUSTOMER ACCOUNTS EXPENSES - OPERATION**					
8	Supervision (901)				-	-
9	Meter reading expenses (902)				266,118	(114,409)
10	Customer records & collection expenses (903)				1,643,786	155,591
11	Uncollectible accounts (904)				243,180	(13,820)
12	Miscellaneous customer accounts expenses (905)				1,851	1,353
13	Customer Service & Informational Expenses (906)				-	-
14	Supervision (907)				-	-
15	Customer assistance expenses (908)				86	86
16	Informational & instructional advertising expenses (909)				-	-
17	Miscellaneous customer service & informational expenses (910)				-	-
18						
19	**Total customer accounts expenses**			E-1 Line 35	2,155,021	28,800
20						
21	**SALES EXPENSES**					
22	Sales Expenses (911-917)			E-1 Line 36	171,023	17,449
23	**ADMINISTRATIVE AND GENERAL EXPENSES**					
24	Administrative and general salaries (920)				1,513,145	378,149
25	Office supplies and expenses (921)				364,274	37,305
26	Administrative expenses transferred--cr. (922)				-	-
27	Outside services employed (923)				256,352	(61,933)
28	Property insurance (924)				-	-
29	Injuries and damages (925)				209,399	62,910
30	Employee pensions and benefits (926)				61,832	55,782
31	Regulatory commission expenses (927-928)				256,621	22,397
32	Du;licate Charges -Credit (929)				-	-
33	General Advertising & Miscellaneous general expenses (930.1-930.99)				560,697	76,510
34	Transportation expenses (933)				-	-
35	Maintenance of general plant (932)				165,041	33,118
36	Rents (931)				-	-
37					-	-
38	**Total administrative and general expenses**			E-1 Line 37	3,387,360	604,239
39						
40						
41	**Total operation and maintenance expenses**			E-1 Line 39	60,757,232	430,815
42						
43						
44						

OTHER OPERATING REVENUES

Describe hereunder items of miscellaneous revenues included in accounts 451,453,454,455, and 456, showing separate total for each account

	PARTICULARS (a)					
51	451.00 Misc Service Revenue: Fees					641,583
52	Trip Fees: Collection and Connections	189,892				
53	Account Fees: Establishment and Continuous Service	107,670				
54	Penalty Fees: Power Factor	99,415				
55	Misc: Including NSF Reimb. Fees	244,607				
56	454.00 Attachment Fees					121,576
57	456.00 - 456.40 Transmission for Others Revenues					998,648
58	ISO-NE OATT Sch 21-VEC Great Bay Schedule 8		100,546			
59	ISO-NE OATT Sch 21-VEC VPPI (Standard Offer-SPEED) Schedule 8		24,342			
60	ISO-NE OATT Sch 21-VEC Swanton Village Schedule 9		152			
61	SC 803 803 CVPS-Belvidere Center		9,340			
62	SC 805 Missisquoi Associates Sheldon Hydro to VELCO Highgate		211,504			
63	SC 806 Block Loading Facilities Transmission Agreement CVPS		421,200			
64	SC 806 Block Loading Facilities Transmission Agreement Barton		15,374			
65	SC 806 Block Loading Facilities Transmission Agreement Enosburg		19,923			
66	SC 806 Block Loading Facilities Transmission Agreement VT Marble		21,060			
67	SC 807 FPC-10 Enosburg Village		37,396			
68	SC 808 Highgate Lease Vermont Marble Company		15,974			
69	Phase II Vermont DMNRC Support Agreement (456.40)		121,839			

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 17, 2011	RTO ROE filing
Revenue Requirements for (year):	**Calendar Yr 2010** $ 1,472,293	
Customer:		
Customer's NABs Number:		
Name of Participant responsible for customer's billing:		
DUNs number of Participant responsible for customer's billing:		

	Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I =	1,472,293	(a)		(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)	0	(d)		(i)
Sub Total - Sum (A through I) - J + K + (L through O)	1,472,293	(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:	1,472,293	(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: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)	1,472,293	(l)=(k)+(b)+(g)-(h)

Annual Revenue Requirements of PTF Facilities
for costs in 2010

▨ Shading denotes an input

Line N	I. INVESTMENT BASE	Attachment F Reference Section:	Total	Reference
1	Transmission Plant	(A)(1)(a)	10,340,910	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	296,989	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)		10,637,899	
5	Accumulated Depreciation	(A)(1)(d)	4,454,491	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	1,610,133	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)	10,116	Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		4,583,391	
10	Prepayments	(A)(1)(h)	11,377	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	8,858	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	49,604	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		4,653,230	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	625,158	Worksheet 2
15	Depreciation Expense	(B)	265,177	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)	(6,023)	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	191,151	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	0	*Worksheet 4, line 23 column 5*
20	Operation & Maintenance Expense	(G)	291,076	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	105,754	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 Ta	(N)		
28	Transmission Rents Received from Electric Propert	(O)		
29	Total Revenue Requirements (Line 14 thru 28)		1,472,293	

Annual Revenue Requirements
for costs in 2010

▨ Shading denotes an input

		CAPITALIZATION 12/31/2010	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTIO
LONG-TERM DEBT	$	169,145,000	45.64%	6.30%	2.88%	
PREFERRED STOCK		0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY		201,479,715	54.37%	11.64%	6.33%	6.33%
TOTAL INVESTMENT	$	370,624,715	100.01%		9.21%	6.33%

Cost of Capital Rate=

(a) Weighted Cost of (	=		0.0921										
(b) Federal Income Ta	=		R.O.E. +	(	PTF Inv. (Tax Credit	+	Eq. AFUDC of Deprec)	/ PTF Inv. Base)		x	Federal Income Tax Rate	)	
		(								-	Federal Income Tax Rate	)	
	=		0.0633	+	(6,023)	+	0 `	4,653,230	)	x	0.35	)	I know GMP and CVPS a
		(	1							-	0.35	)	
	=		0.0333876										
(c) State Income Tax	=		R.O.E. +	(	PTF Inv. (Tax Credit	+	Eq. AFUDC of Deprec)	/ PTF Inv. Base)		+	Federal Income Tax	)* State Income Tax Rate	
		(	1							-	State Income Tax Rate	)	
	=		0.0633	+	(6,023)	+	0)	/ 4,653,230	)	+	0.0333876	)* 0.085	
		(	1							-	0.085	)	
	=		0.0088617										
(a)+(b)+(c) **Cost of C**	=		0.1343493										

		(PTF)	
INVESTMENT BASE	$	4,653,230	From Worksheet 1
x Cost of Capital Rate		0.1343493	
= Investment Return and In		625,158	To Worksheet 1

🟨 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 (
	Transmission Plant						
1	Transmission Plant	49,968,849		49,968,849		10,340,910	Line 1, Workshe
2	General Plant	40,907,162	3.5082% (a	1,435,096	20.6947%	296,989	Page 207.99g
3	Total (line 1+2)			51,403,945		10,637,899	
4	Transmission Plant Held for Future Use	0		0	20.6947%	0	Page 214.47d
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	21,060,450		21,060,450	20.6947%	4,358,397	Page 219.25b
6	General Plant Accum.Depreciation	13,235,903	3.5082% (a	464,339	20.6947%	96,094	Page 219.28b
7	Total (line 5+6)			21,524,789		4,454,491	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	100,206,546	11.2168% (c)	11,239,968	20.6947%	2,326,078	Page 113.(57-6
9	Accumulated Deferred Taxes (190)	(30,842,630)	11.2168% (c)	(3,459,556)	20.6947%	(715,945)	Page 111.82c
10	Total (line 8+9)			7,780,412		1,610,133	
11	Transmission loss on Reacquired Debt	0	11.2168% (c)	0	20.6947%	0	Page 111.81d
	Other Regulatory Assets						
12	FAS 106	0	3.5082% (a	0	20.6947%	0	Page 232.30e
13	FAS 109	1,691,208	11.2168% (c)	189,699	20.6947%	39,258	Page 232.21&2
14	Other Regulatory Liabilities (254.DK)	(1,255,409)	11.2168% (c)	(140,817)	20.6947%	(29,142)	Page 278.1&2f
15	Total (line 12+13+14)	435,799		48,882		10,116	
16	Transmission Prepayments	1,567,017	3.5082% (a	54,974	20.6947%	11,377	Page 111.57c
17	Transmission Materials and Supplies	42,804		42,804	20.6947%	8,858	Page 227.8c
18	Cash Working Capital						
19	Operation & Maintenance Expense					291,076	Worksheet 1, Li
20	Administrative & General Expense					105,754	Worksheet 1, Li
21	Transmission Support Expense					0	Worksheet 1, Li
22	Subtotal (line 19+20+21)					396,830	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					49,604	

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

0

PTF Revenue Requirements
Worksheet 4a of 8

Sheet: Worksheet 4

▨ Shading denotes an input

Line No.		(1) Total	(2) for costs in 2005 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	Transmission Depreciation	1,222,922		1,222,922	20.6947%	253,080	Page 336.7b
2	General Depreciation	1,666,282	3.5082% (a)	58,456	20.6947%	12,097	Page 336.10b
3	Total (line 1+2)			1,281,378		265,177	
4	Amortization of Loss on Reacquired Debt	0	11.2168% (c)	0	20.6947%	0	Page 117.64c
5	Amortization of Investment Tax Credits	259,449	11.2168% (c)	29,102	20.6947%	6,023	Page 266.8f
	Property Taxes *						
6	Transmission Property Taxes	6,272,814	11.2168% (c)	703,609	20.6947%	145,610	Page 262-263 FN.1-2
7	General Property Taxes	6,272,814	3.5082%	220,061	20.6947%	45,541	Page 262-263 FN.1-2
8	Total (line 6+7)			923,670		191,151	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	24,290,295		24,290,295	20.6947%	5,026,804	Page 321.112b
10	Transmission of Electricity by Others - #565	22,561,217		22,561,217	20.6947%	4,668,976	Page 321.96b
11	Load Dispatching - #561	85,185		85,185	20.6947%	17,629	Page 321.84b
12	**Station Expenses & Rents - #562 / #567	237,369		237,369	20.6947%	49,123	Page 321.93b & .98b
13	O&M less lines 10, 11 & 12	1,406,524		1,406,524	`	291,076	
	Transmission Administrative and General						
14	Administrative and General	12,516,207					Page 323.197b
15	*less Property Insurance (#924)*	*409,241*					*Page 323.185b*
16	*less Regulatory Commission Expenses (#928)*	*592,364*					*Page 323.189b*
17	*less General Advertising Expense (#930.1)*	*150,526*					*Page 323.191b*
18	Subtotal [line 14 minus (15 thru 17)]	11,364,076	3.5082% (a)	398,672	20.6947%	82,504	
19	*PLUS Property Insurance alloc. using Plant Allocation*	*409,241*	11.2168% *(c)*	45,904	20.6947%	9,500	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	*592,364*	11.2168% *(c)*	66,444	20.6947%	13,750	
21	*PLUS Trans. Related General Advertising Expense*	*0*	11.2168% *(c)*	0	20.6947%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*12,365,681*		*511,020*		*105,754*	
23	*Payroll Tax Expense*		3.5082% *(a)*	*0*	20.6947%	*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*

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

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	**GMP**	
1	PTF Transmission Investment	10,340,910	FIXED ASSET ROLL FORWARD
2	Total Transmission Investment	49,968,849	Page 207.58g
3	Percent Allocation (Line 1/Line 2)	20.6947%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	275,364	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	275,364	
7	Total Wages and Salaries	11,694,858	Page 354.28b
8	Administrative and General Wages and Salaries	3,845,655	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)	7,849,203	
11	Percent Allocation (Line 6/Line 10)	3.5082%	`
	Plant Allocation Factor		
12	Total Transmission Investment	49,968,849	Page 207.58g
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*		*Page 207.99g*
14	*= Revised Numerator (Line 12 + Line 13)*	49,968,849	
15	Total Plant in Service	445,480,767	Page 207.104g
16	Percent Allocation (Line 14 / Line 15)	11.2168%	

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 exp
with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23

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	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 3	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 li	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 17, 2011 RTO ROE filing

Revenue Requirements for (year): **Calendar Yr 2010** $ 236,854

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:

		Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I	=	236,854	(a)		(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)		0	(d)		(i)
Sub Total - Sum (A through I) - J + K + (L through O)		236,854	(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:	236,854	(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: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)	236,854	(l)=(k)+(b)+(g)-(h)

Annual Revenue Requirements of PTF Facilities
for costs in 2010

▨ Shading denotes an input

Line N			Attachment F Reference Section:	Total	Reference
	I.	INVESTMENT BASE			
1		Transmission Plant	(A)(1)(a)	3,051,330	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)		3,071,167	
5		Accumulated Depreciation	(A)(1)(d)	2,761,002	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)		310,165	
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)	19,011	Worksheet 3, line 23 column 5
13		Total Investment Base (Line 9+10+11+12)		329,176	
	II.	REVENUE REQUIREMENTS			
14		Investment Return and Income Taxes	(A)	38,316	Worksheet 2
15		Depreciation Expense	(B)	9,323	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)	37,124	Worksheet 4, line 8 column 5
19		Payroll Tax Expense	(F)	0	*Worksheet 4, line 23 column 5*
20		Operation & Maintenance Expense	(G)	46,631	Worksheet 4, line 13 column 5
21		Administrative & General Expense	(H)	105,460	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 Ta	(N)		
28		Transmission Rents Received from Electric Propert	(O)		
29		Total Revenue Requirements (Line 14 thru 28)		236,854	

Annual Revenue Requirements
for costs in 2010

▨ Shading denotes an input

		CAPITALIZATION 12/31/2010	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		414,225	100.01%	11.64%	11.64%	11.64%
TOTAL INVESTMENT	$	414,225	100.01%		11.64%	11.64%

Cost of Capital Rate=

(a) Weighted Cost of (= 0.1164

(b) Federal Income Ta =

			PTF Inv.		Eq. AFUDC				
	R.O.E. +	(	(Tax Credit	+	of Deprec)	/ PTF Inv. Base)	x	Federal Income Tax Rate	)
(							-	Federal Income Tax Rate	)
=	0.1164	+	0	+	0 `	329,176)	x	0	)
(	1						-	0	)
=	0.0000000								

(c) State Income Tax =

			PTF Inv.		Eq. AFUDC				
	R.O.E. +	(	(Tax Credit	+	of Deprec)	/ PTF Inv. Base)	+	Federal Income Tax	)* State Income Tax Rate
(	1						-	State Income Tax Rate	)
=	0.1164	+	0	+	0) /	329,176)	+	0.0000000	)* 0
(	1						-	0	)
=	0.0000000								

(a)+(b)+(c) **Cost of C** = 0.1164000

		(PTF)	
INVESTMENT BASE	$	329,176	From Worksheet 1
x Cost of Capital Rate		0.1164000	
= Investment Return and In		38,316	To Worksheet 1

▨ Shading denotes an input

ine 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 (
	Transmission Plant							
1	Transmission Plant	3,051,330			3,051,330		3,051,330	Line 1, Workshe
2	General Plant	19,837	100.0000%	(a	19,837	100.0000%	19,837	Page 207.90g
3	Total (line 1+2)	3,071,167			3,071,167		3,071,167	
4	Transmission Plant Held for Future Use	0			0	100.0000%	0	Page 214.47d
	Transmission Accumulated Depreciation							
5	Transmission Accum. Depreciation	2,741,165			2,741,165	100.0000%	2,741,165	Page 219.25b
6	General Plant Accum.Depreciation	19,837	100.0000%	(a	19,837	100.0000%	19,837	Page 219.28b
7	Total (line 5+6)	2,761,002			2,761,002		2,761,002	
	Transmission Accumulated Deferred Taxes							
8	Accumulated Deferred Taxes (281-283)	0	100.0000%	(c	0	100.0000%	0	Page 113.(57-6
9	Accumulated Deferred Taxes (190)	0	100.0000%	(c	0	100.0000%	0	Page 111.82c
10	Total (line 8+9)				0		0	
11	Transmission loss on Reacquired Debt	0	100.0000%	(c	0	100.0000%	0	Page 111.81d
	Other Regulatory Assets							
12	FAS 106	0	100.0000%	(a	0	100.0000%	0	Page 232.30e
13	FAS 109	0	100.0000%	(c	0	100.0000%	0	Page 232.21&2
14	Other Regulatory Liabilities (254.DK)	0	100.0000%	(c	0	100.0000%	0	Page 278.1e
15	Total (line 12+13+14)	0			0		0	
16	Transmission Prepayments	0	100.0000%	(a	0	100.0000%	0	Page 111.57c
17	Transmission Materials and Supplies	0			0	100.0000%	0	Page 227.8c
18	Cash Working Capital							
19	Operation & Maintenance Expense						46,631	Worksheet 1, Li
20	Administrative & General Expense						105,460	Worksheet 1, Li
21	Transmission Support Expense						0	Worksheet 1, Li
22	Subtotal (line 19+20+21)						152,091	
23							0.125	x 45 / 360
24	Total (line 22 * line 23)						19,011	

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

Sheet: Worksheet 4

▨ Shading denotes an input

Line No.		(1) Total	(2) for costs in 2005 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	Transmission Depreciation	9,323		9,323	100.0000%	9,323	Page 336.7b
2	General Depreciation	0	100.0000% (a)	0	100.0000%	0	Page 336.10b
3	Total (line 1+2)			9,323		9,323	
4	Amortization of Loss on Reacquired Debt	0	100.0000% (c)	0	100.0000%	0	Page 117.64c
5	Amortization of Investment Tax Credits	0	100.0000% (c)	0	100.0000%	0	Page 266.8f
	Property Taxes *						
6	Transmission Property Taxes	37,124	100.0000% (c)	37,124	100.0000%	37,124	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)	37,124		37,124		37,124	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	46,631		46,631	100.0000%	46,631	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	46,631		46,631	`	46,631	
	Transmission Administrative and General						
14	Administrative and General	105,460					Page 323.197b
15	*less Property Insurance (#924)*	*13,683*					*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)]	91,777	100.0000% (a)	91,777	100.0000%	91,777	
19	*PLUS Property Insurance alloc. using Plant Allocation*	*13,683*	100.0000% *(c)*	13,683	100.0000%	13,683	
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)]	*105,460*		*105,460*		*105,460*	
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*

** 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	3,051,330	NEPOOL Catalog
2	Total Transmission Investment	3,051,330	Page 207.58g
3	Percent Allocation (Line 1/Line 2)	100.0000%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	1,424	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	1,424	
7	Total Wages and Salaries	32,570	Page 354.28b
8	Administrative and General Wages and Salaries	31,146	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)	1,424	
11	Percent Allocation (Line 6/Line 10)	100.0000%	`
	Plant Allocation Factor		
12	Total Transmission Investment	3,051,330	Page 207.58g
13	*plus Transmission-Related General Plant (Line 2 of Wkst.*	19,837	*Page 207.99g*
14	*= Revised Numerator (Line 12 + Line 13)*	3,071,167	
15	Total Plant in Service	3,071,167	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
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 exp with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23

			TOTAL	
Particip	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 3	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 li	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)

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

TOTAL

Submitted on:	May 17, 2011	RTO ROE filing
Revenue Requirements for (year):	**Calendar Yr 2010** $ 12,549	
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:		

	Pre-97 Revenue Requirements		Post-96 Revenue Requirements		
Total of Attachment F - Sections A through I =	12,549	(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)	0	(d)		(i)	N/A for Johnson
Sub Total - Sum (A through I) - J + K + (L through O)	12,549	(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:	12,549	(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: (for Voting Share and expense allocation calculations under the Restated NEPOOL Agreement)	12,549	(l)=(k)+(b)+(g)-(h)	

Village of Johnson
Annual Revenue Requirements of PTF Facilities
for costs in 2009

PTF Revenue Requirements
Worksheet 1 of 8

▨ Shading denotes an input

Line N	I. INVESTMENT BASE	Attachment F Reference Section:	Total	Reference	
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)	73,135	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)		43,882		
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)	346	Worksheet 3, line 23 column 5	
13	Total Investment Base (Line 9+10+11+12)		44,228		
	II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	5,148	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 VPPSA
17	Investment Tax Credit	(D)	0	Worksheet 4, line 5 column 5	N/A for VPPSA
18	Property Tax Expense	(E)	1,705	Worksheet 4, line 8 column 5	
19	Payroll Tax Expense	(F)	0	*Worksheet 4, line 23 column 5*	N/A for VPPSA
20	Operation & Maintenance Expense	(G)	2,142	Worksheet 4, line 13 column 5	
21	Administrative & General Expense	(H)	629	Worksheet 4, line 16 column 5	
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7	N/A for VPPSA
23	Transmission Support Revenue	(J)	0	Worksheet 7	N/A for VPPSA
24	Transmission Support Expense	(K)	0	Worksheet 7	N/A for VPPSA
25	Transmission Related Expense from Generators	(L)	0	Worksheet 7	N/A for VPPSA
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)		12,549		

Village of Johnson

Annual Revenue Requirements
for costs in 2009

▨ Shading denotes an input

		CAPITALIZATION 12/31/2009	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		1,534,401	100.01%	11.64%	11.64%	11.64%
TOTAL INVESTMENT RE	$	1,534,401	100.01%		11.64%	11.64%

Cost of Capital Rate=

(a) Weighted Cost of Capi = 0.1164

(b) Federal Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec) / PTF Inv. Base) x Federal Income Tax Rate) / (- Federal Income Tax Rate)

= (0.1164 + 0 + 0 ` 44,228) x 0) / (1 - 0) N/A for John

= 0.0000000

(c) State Income Tax = (R.O.E. + (PTF Inv. (Tax Credit + Eq. AFUDC of Deprec) / PTF Inv. Base) + Federal Income Tax)* State Income Tax Rate / (1 - State Income Tax Rate)

= (0.1164 + 0 + 0) / 44,228) + 0.0000000)* 0 / (1 - 0)

= 0.0000000

(a)+(b)+(c) **Cost of Capit** = 0.1164000

		(PTF)	
INVESTMENT BASE	$	44,228	From Worksheet 1
x Cost of Capital Rate		0.1164000	
= Investment Return and Incom		5,148	To Worksheet 1

Shading denotes an input

fo

	(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)	
Transmission Plant							
Transmission Plant	117,017		117,017		117,017	Line 1, Worksheet 5	
General Plant	0	0.0000% (a)	0	100.0000%	0	Page 207.90g	
Total (line 1+2)	117,017		117,017		117,017		
Transmission Plant Held for Future Use	0		0	100.0000%	0	Page 214.47d	N/A for Johnson
Transmission Accumulated Depreciation							
Transmission Accum. Depreciation	73,135		73,135	100.0000%	73,135	Page 219.25b	
General Plant Accum.Depreciation	0	0.0000% (a)	0	100.0000%	0	Page 219.28b	
Total (line 5+6)	73,135		73,135		73,135		
Transmission Accumulated Deferred Taxes							
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		
Transmission loss on Reacquired Debt	0	100.0000% (c)	0	100.0000%	0	Page 111.67d	N/A for Johnson
Other Regulatory Assets							
FAS 106	0	0.0000% (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		
Transmission Prepayments	0	0.0000% (a)	0	100.0000%	0	Page 110.57c	N/A for Johnson
Transmission Materials and Supplies	0		0	100.0000%	0	Page 227.8c	N/A for Johnson
Cash Working Capital							
Operation & Maintenance Expense					2,142	Worksheet 1, Line 20	
Administrative & General Expense					629	Worksheet 1, Line 21	
Transmission Support Expense					0	Worksheet 1, Line 24	
Subtotal (line 19+20+21)					2,771		
					0.125	x 45 / 360	
Total (line 22 * line 23					346		

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

Village of Johnson

PTF Revenue Requirements
Worksheet 4a of 8

Sheet: Worksheet 4

▨ Shading denotes an input

Line No.		(1) Total	(2) for costs in 2008 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	Transmission Depreciation	2,925		2,925	100.0000%	2,925	Page 336.7b
2	General Depreciation	0	0.0000% (a)	0	100.0000%	0	Page 336.9b
3	Total (line 1+2)	2,925		2,925		2,925	
4	Amortization of Loss on Reacquired Debt	0	100.0000% (c)	0	100.0000%	0	Page 117.60c
5	Amortization of Investment Tax Credits	0	100.0000% (c)	0	100.0000%	0	Page 266.8f
	Property Taxes*						
6	Transmission Property Taxes	1,705	100.0000% (c)	1,705	100.0000%	1,705	Page 262-263 FN.1-2
7	General Property Taxes	0	0.0000%	0	100.0000%	0	Page 262-263 FN.1-2
8	Total (line 6+7)	1,705		1,705		1,705	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	2,142		2,142	100.0000%	2,142	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 321.93b & .98b
13	O&M less lines 10, 11 & 12	2,142		2,142	`	2,142	
	Transmission Administrative and General						
14	Administrative and General	784					Page 323.197b
15	*less Property Insurance (#924)*	*629*					*Page 323.186b*
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)]	155	0.0000% (a)	0	100.0000%	0	
19	*PLUS Property Insurance alloc. using Plant Allocatior*	*629*	100.0000% *(c)*	629	100.0000%	629	
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)]	*784*		*629*		*629*	
23	*Payroll Tax Expense*		0.0000% *(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*

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

0	Comerford - Take out because - Support Payment included on Worksheet 7
0	net

Sheet: Worksheet 5

PTF Revenue Requirements
Worksheet 5 of 8

🟨 Shading denotes an input

for costs in 2010

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)	100.0000%		
	Transmission Wages and Salaries Allocation Factor			
4	Direct Transmission Wages and Salaries	65	Page 354.21b	
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 & 6a c	N/A for Johnson
6	Total Transmission Wages and Salaries (Line 4 + Line	65		
7	Total Wages and Salaries	0	Page 354.28b	
8	Administrative and General Wages and Salaries	0	Page 354.27b	N/A for Johnson
9	Affiliated Company Wages and Salaries less A&G	0	Worksheet 6 & 6a c	N/A for Johnson
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	0		
11	Percent Allocation (Line 6/Line 10)	0.00%		`
	Plant Allocation Factor			
12	Total Transmission Investment	117,017	Page 207.58g	
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*		*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)	100.0000%		

Affiliated Company Wages and Salaries

🟨 Shading denotes an input

N/A for Johnson
Johnson has no "affiliated" wages & sa

Line			**Johnson**
"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.

			TOTAL	
Particip	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 3	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 li	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 2011

June 1, 2011 RNS Rates
Regional Forecast Summary

(A)		(B)	(C)		(D) = (C) / Load
Participating Transmission Owner		**Total Estimated 2011 PTF Capital Costs ($)**	**Forecasted PTF Revenue Requirement ($)**		**6/1/11 RNS Rate Impact ($/kW-yr.)**
CMP		491,023,924	82,660,470		3.92008
NU		535,108,000	81,075,000		3.84489
NGRID		126,976,131	19,133,246		0.90737
CTMEEC		47,914,102	7,378,334		0.34991
NSTAR		48,995,000	6,721,127		0.31874
BHE		38,500,000	6,575,240		0.31182
VT Transco		20,800,000	3,420,235		0.16220
NHT		2,600,000	530,686		0.02517
HG&E		62,500	13,679		0.00065
UI	(a)	(8,672,760)	(1,742,480)		(0.08264)
		1,303,306,897	205,765,537		9.75820
2010 RTO-NE 12 -CP RNS Load:			21,086,421	kW	

(a) Reflects ISO-NE's final determinations of the transmission cost allocation (TCA) application for the Middletown-Norwalk (M-N) project.

Attachment 4

Annual True-up Summary

June 1, 2011 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 2009 Actual + 2010 Forecast (As Billed)**	**RNS Rev Req'ts 2010 Actual (For True-up)**	**Difference (overcollection), undercollection**	**Interest on Difference**	**Annual True Up and Associated Interest**	**6/1/11 RNS Rate Impact ($/kW-yr.)**
NSTAR		151,484,527	$ 153,377,179	$ 1,892,652	$ 63,070	1,955,722	0.09275
NHT		9,387,263	$ 11,223,789	$ 1,836,526	$ 61,199	1,897,725	0.09000
BHE		35,313,311	$ 34,612,538	$ (700,773)	$ (23,352)	(724,125)	(0.03434)
CMP		82,751,023	$ 79,564,983	$ (3,186,040)	$ (106,170)	(3,292,210)	(0.15613)
UI		100,078,331	$ 93,710,642	$ (6,367,689)	$ (212,193)	(6,579,882)	(0.31204)
VT Transco		111,656,154	$ 104,337,053	$ (7,319,101)	$ (243,897)	(7,562,998)	(0.35867)
NGRID		213,423,879	$ 196,248,448	$ (17,175,431)	$ (572,343)	(17,747,774)	(0.84167)
NU 2010		529,818,997	$ 521,678,957	$ (8,140,040)	$ (271,254)	(8,411,294)	(0.39890)
NU (M-N & G-C Adj)	(a)			$ (24,180,932)	$ (2,595,016)	(26,775,948)	(1.26982)
		$ 1,233,913,485	$ 1,194,753,589	$ (63,340,828)	$ (3,899,956)	$ (67,240,784)	(3.18882)
		2010 RTO-NE 12-CP RNS Load:	21,086,421	kW			

(a) Reflects ISO-NE's final determinations of the transmission cost allocation (TCA) applications for the Middletown-Norwalk (M-N) and Glenbrook Cables (G-C) projects.

Attachment 5

Schedule 1 Rates Effective June 1, 2011 – May 31, 2012
Based on 2010 Data

SUMMARY

ISO NE Transmission, Markets & Services Tariff
OATT Regional Schedule 1 - Scheduling System Control and Dispatch Service Rate
Effective June 1, 2011 - May 31, 2012
(Reflecting 2010 Schedule 1 Costs)

1	Total of FERC account 561-561.4 (exclude REMVEC & CONVEX costs)	$ 13,810,947	1
2	Less ISO & OATT Sch 1 costs included in above accounts	1,648,223	2
3	Sub-total(1-2)	12,162,724	3
4	Amount allocated to transmission function	12,162,724	4
5	Transmission related S&D costs from SCADA or other systems	7,485,238	5
6	Sub-total (4+5)	19,647,962	6
7	PTF allocation factors (see page 2 for details)	78.8500%	7
8	Sub-total after applying ptf allocation factors (from page 2)	15,492,426	8
9	Maine LCC costs	4,478,955	9
10	REMVEC II costs	1,494,709	10
11	CONVEX costs	13,706,188	11
12	Sub-total (9+10+11)	19,679,852	12
13	100% allocated to transmission function	19,679,852	13
14	Revenues credited for short-term Transmission Service	(1,811,138)	14
15	Total transmission related system & dispatch revenue requirement (8+13+14)	33,361,140	15
16	12 month CP LOAD (KW) as defined in section 46.1 of the ISO-NE Tariff	21,086,421	16
17	Long Term Firm PTP Capacity (KW)	-	17
18	Scheduling System Control and Dispatch Service Rate ($/KW YR): (15/(16+17))	$ 1.58211	18

DETAIL

ISO NE Transmission, Markets & Services Tariff
OATT Regional Schedule 1 - Scheduling System Control and Dispatch Service Rate
Effective June 1, 2011 - May 31, 2012
(Reflecting 2010 Schedule 1 Costs)

				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15		16	
	Customer #	DUNS	DUNS Name	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 %	
1	3	00-695-1552	NSTAR					7,485,238	7,485,238	87.5691%	6,554,755				-	-	(334,271)	6,220,484	1	18.6459%	NSTAR
2	2	00-694-9002	Bangor Hydro Transmission	465,429		465,429	465,429		465,429	66.4772%	309,404	299,565			299,565	299,565	(46,708)	562,261	2	1.6854%	BH
3	6	00-694-8954	Central Maine Power Transmission			-	-		-		-	3,986,419			3,986,419	3,986,419	(258,926)	3,727,493	3	11.1732%	CMP
4	6	06-099-4258	Maine Electric Power Company			-	-		-		-	192,971			192,971	192,971	(9,074)	183,897	4	0.5512%	MEPCO
5	1	83-729-7852	Ashburnham, Town of			-	-		-		-		536		536	536	(30)	506	5	0.0015%	Ashburham
6	4	06-991-6021	Boylston, Town of			-	-		-		-		503		503	503	(28)	475	6	0.0014%	Boylston
7	5	17-057-1897	Braintree, Town of			-	-		-		-		8,196		8,196	8,196	(33)	8,163	7	0.0245%	Braintree
8	9	15-596-9157	Danvers, Town of			-	-		-		-		6,642		6,642	6,642	(360)	6,282	8	0.0188%	Danvers
9	38	00-695-4317	Unitil Fitchburg Gas & Electric Company Inc	144,466	121,278	23,188	23,188		23,188	20.8358%	4,831		9,579		9,579	9,579	(851)	13,559	9	0.0406%	FG&E
10	39	15-596-9983	Georgetown, Town of			-	-		-		-		705		705	705	(39)	666	10	0.0020%	Georgetown
11	40	15-601-8301	Groton, Town of			-	-		-		-		947		947	947	(52)	895	11	0.0027%	Groton, MA
12	42	14-703-0704	Hingham, Town of			-	-		-		-		3,096		3,096	3,096	(169)	2,927	12	0.0088%	Hingham
13	43	87-808-0563	Holden, Town of			-	-		-		-		1,907		1,907	1,907	(104)	1,803	13	0.0054%	Holden
14	45	10-775-5126	Hudson, Town of			-	-		-		-		5,880		5,880	5,880	(319)	5,561	14	0.0167%	Hudson
15	72	13-661-7156	Hull, Town of			-	-		-		-		878		878	878	(48)	830	15	0.0025%	Hull
16	73	15-586-9563	Ipswich, Town Of			-	-		-		-		1,973		1,973	1,973	(107)	1,866	16	0.0056%	Ipswich
17	75	79-432-5019	Littleton, Town of			-	-		-		-		4,321		4,321	4,321	(234)	4,087	17	0.0123%	Littleton, MA
18	77	95-690-6051	Mansfield, Town of			-	-		-		-		4,320		4,320	4,320	(234)	4,086	18	0.0122%	Mansfield
19	78	15-598-9544	Marblehead, Town of			-	-		-		-		2,098		2,098	2,098	(113)	1,985	19	0.0060%	Marblehead
20	79	15-597-6665	Middleborough, Town of			-	-		-		-		2,600		2,600	2,600	(141)	2,459	20	0.0074%	Middleboro
21	80	18-675-8231	Middleton, Town of			-	-		-		-		1,505		1,505	1,505	(82)	1,423	21	0.0043%	Middleton
22	111	10-798-9241	North Attleboro Electric			-	-		-		-		4,326		4,326	4,326	(235)	4,091	22	0.0123%	N.Attleboro
23	116	06-984-9461	Pascoag Utility District			-	-		-		-		459		459	459	(24)	435	23	0.0013%	Pascoag
24	117	15-582-5391	Paxton, Town of			-	-		-		-		402		402	402	(22)	380	24	0.0011%	Paxton
25	144	10-371-6353	Peabody, City of			-	-		-		-		8,736		8,736	8,736	(474)	8,262	25	0.0248%	Peabody
26	145	96-152-2786	Princeton, Town of			-	-		-		-		290		290	290	(17)	273	26	0.0008%	Princeton
27	148	86-703-4654	Reading, Town of			-	-		-		-		8,622		8,622	8,622	(468)	8,154	27	0.0244%	Reading
28	146	11-885-5188	Rowley, Town of			-	-		-		-		582		582	582	(32)	550	28	0.0016%	Rowley
29	149	78-451-8870	Shrewsbury, Town of			-	-		-		-		5,817		5,817	5,817	(315)	5,502	29	0.0165%	Shrewsbury
30	152	15-586-0620	Sterling, Town of			-	-		-		-		753		753	753	(41)	712	30	0.0021%	Sterling
31	153	04-661-6033	Taunton Municipal Lighting Plant			-	-		-		-		10,951		10,951	10,951	(595)	10,356	31	0.0310%	Taunton
32	180	02-619-2302	Templeton, Town of			-	-		-		-		1,649		1,649	1,649	(89)	1,560	32	0.0047%	Templeton
33	183	15-415-7622	Wakefield Municipal Gas & Light Department			-	-		-		-		3,466		3,466	3,466	(188)	3,278	33	0.0098%	Wakefield
34	186	12-787-0350	West Boylston, Town of Inc			-	-		-		-		1,232		1,232	1,232	(67)	1,165	34	0.0035%	W.Boylston
35	81	00-695-2881	New England Electric Transmission	9,173,048		9,173,048	9,173,048		9,173,048	71.6400%	6,571,572		1,391,738		1,391,738	1,391,738	(426,870)	7,536,440	35	22.5905%	NGRID
36			Connecticut Light & Power	58,428		58,428	58,428		58,428	88.5452%	51,735			12,674,236	12,674,236	12,674,236	(574,187)	12,151,784	36	36.4252%	CL&P
37			Public Service of New Hampshire	196,278		196,278	196,278		196,278	93.1281%	182,790			1,022,200	1,022,200	1,022,200	(49,984)	1,155,006	37	3.4621%	PSNH
38			Western Massachusetts Electric Co.	38,835		38,835	38,835		38,835	89.2536%	34,662			9,752	9,752	9,752	(1,237)	43,177	38	0.1294%	WMECO
39	112	95-910-8929	Northeast Utilities Transmission	293,541	-	293,541	293,541		293,541		269,187			13,706,188	13,706,188	13,706,188	(625,408)	13,349,967	39	40.0167%	Total submitted by NU
40			Chicopee			-	-		-		-				-	-		-	40	0.0000%	Chicopee
41	8	09-207-8351	Connecticut Municipal Electric Energy Cooperative			-	-		-		-				-	-		-	41	0.0000%	CMEEC
42	44	08-465-0050	Holyoke Gas & Electric Department			-	-		-		-				-	-		-	42	0.0000%	Holyoke
43			S. Hadley			-	-		-		-				-	-		-	43	0.0000%	S. Hadley
44			Westfield Gas & Electric			-	-		-		-				-	-		-	44	0.0000%	Westfield Gas & Electric
45	181	00-691-7967	The United Illuminating Company	1,555,605	1,526,945	28,660	28,660		28,660	95.6474%	27,413				-	-	(787)	26,626	45	0.0798%	UI
46	50853	78-039-9163	Vermont Trans	2,178,858		2,178,858	2,178,858		2,178,858	80.5589%	1,755,264				-	-	(103,583)	1,651,681	46	4.9509%	VTransco
47			TOTALS	$ 13,810,947	$ 1,648,223	$ 12,162,724	$ 12,162,724	$ 7,485,238	$ 19,647,962	78.8500%	$ 15,492,426	$ 4,478,955	$ 1,494,709	$ 13,706,188	$ 19,679,852	$ 19,679,852	$ (1,811,138)	$ 33,361,140	47	100.00%	TOTALS

ISO NE Transmission, Markets & Services Tariff
OATT Regional Schedule 1 - Scheduling System Control and Dispatch Service Rate
Effective June 1, 2011 - May 31, 2012
(Reflecting 2010 Schedule 1 Costs)

COMPANY		SCHEDULE 1 DISTRIBUTION %
Ashburham		0.0015%
Bangor Hydro		1.6854%
NSTAR		18.6459%
Boylston		0.0014%
Braintree		0.0245%
Central Maine Power		11.1732%
MEPCO		0.5512%
Chicopee		0.0000%
Connecticut Municiple Electric Energy		0.0000%
Danvers		0.0188%
Fitchburg Gas & Electric		0.0406%
Georgetown		0.0020%
Groton, MA		0.0027%
Hingham		0.0088%
Holden		0.0054%
Holyoke		0.0000%
Hudson		0.0167%
Hull		0.0025%
Ipswich		0.0056%
Littleton, MA		0.0123%
Mansfield		0.0122%
Marblehead		0.0060%
Middleboro		0.0074%
Middleton		0.0043%
N.Attleboro		0.0123%
National Grid		22.5905%
Northeast Utilities		40.0167%
Pascoag		0.0013%
Paxton		0.0011%
Peabody		0.0248%
Princeton		0.0008%
Reading		0.0244%
Rowley		0.0016%
S. Hadley		0.0000%
Shrewsbury		0.0165%
Sterling		0.0021%
Taunton		0.0310%
Templeton		0.0047%
United Illuminating		0.0798%
VTransco		4.9509%
W. Boylston		0.0035%
Wakefield		0.0098%
Westfield Gas & Electric		0.0000%
	TOTAL =	**100.00%**

Attachment 6

PTOs' Annual Revenue Requirement Calculations
Pursuant to Schedule 1 and based on 2010 Data

CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/10

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: **6/1/2011**

Submitted on: **5/18/2011**

Revenue Requirements for (year): **Unadjusted Test Year ended 12/31/10**

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**

		2010 Revenue Requirements	
Total of Appendix A - Sections A through I	=	7,281,082	(a)
Total of Appendix A - Section J - Support Revenue		536,237	(b)
Total Annual Revenue Requirement		$ 6,744,845	(c)=(a)-(b)
Transmission Related Revenue Requirement		$ 6,744,845	(d)= (c)* Satellite Wages & Salaries Allocation F
PTF Related Revenue Requirement		**$ 3,986,419**	(e)= (d)* Satellite PTF Allocation Factor

CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/10

Worksheet 1 of 11

Line No.	II. INVESTMENT BASE	Formula Reference Section:		Reference
1	Local Control Center Plant	II (A)(1)(a)	$ 18,046,161	Worksheet 3, line 1 column 3
3	Plant Held For Future Use	II (A)(1)(b)	2,213	Worksheet 3, line 3 column 3
4	Total Plant (Lines 1+2+3)		18,048,374	
5	Accumulated Depreciation	II (A)(1)(c)	12,534,636	Worksheet 3, line 5 column 3
6	Accumulated Deferred Income Taxes	II (A)(1)(d)	3,372,081	Worksheet 3, line 10 column 3
7	Loss On Reacquired Debt	II (A)(1)(e)	40,074	Worksheet 3, line 12 column 3
8	Other Regulatory Asssets	II (A)(1)(f)	2,803,438	Worksheet 3, line 17 column 3
9	Net Investment (Line 4-5-6+7+8)		4,985,169	
11	Prepayments	II (A)(1)(g)	38,271	Worksheet 3, line 19 column 3
12	Materials & Supplies	II (A)(1)(h)	73,281	Worksheet 3, line 21 column 3
13	Cash Working Capital	II (A)(1)(i)	668,777	Worksheet 3, line 28 column 3
14	Total Investment Base (Line 9+11+12+13)		$ 5,765,498	
II.	REVENUE REQUIREMENTS			
15	Investment Return and Income Taxes	II (A)	$ 885,375	Worksheet 2, line 44
16	Depreciation Expense	II (B)	922,846	Worksheet 4, line 1 column 3
17	Amortization of Loss on Reacquired Debt	II (C)	7,502	Worksheet 4, line 3 column 3
18	Investment Tax Credit	II (D)	(7,541)	Worksheet 4, line 5 column 3
19	Municipal Taxes	II (E)	122,688	Worksheet 4, line 7 column 3
20	Payroll Taxes	II (F)	0	Worksheet 4, line 9 column 3
21	Operation & Maintenance Expense	II (G)	3,728,205	Worksheet 4, line 16 column 3
22	Administrative & General Expense	II (H)	1,622,007	Worksheet 4, line 22 column 3
24	Transmission Support Revenue	II (I)	(536,237)	Worksheet 11, line 6
30	Total Revenue Requirements (Line 15 thru 29)		$ 6,744,845	
	Local Control Center Wages and Salaries Allocation Factor		100.00%	Worksheet 5, line 20
	Transmission Related Revenue Requirement		$ 6,744,845	
	Local Control Center PTF Allocation Factor		59.10%	Worksheet 5, line 29
	PTF Transmission Related Revenue Requirement		$ 3,986,420	

CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/10

Worksheet 2 of 11

			CAPITALIZATION 12/31/10	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION		
1	LONG-TERM DEBT	$	462,700,000	32.380%	6.648%	2.153%			Worksheet 9, line 5
2	PREFERRED STOCK		2,660,500	0.186%	5.062%	0.009%	0.009%		Worksheet 9, line 6
3	COMMON EQUITY		963,604,143	67.434%	11.640%	7.849%	7.849%		Worksheet 9, line 7
4									
5	TOTAL INVESTMENT RETURN	$	1,428,964,643	100.00%		10.011%	7.858%		
6									
7	New Inv Adder Calc.			67.434%		0.000%	0.000%	0.000%	including FIT&SIT

8															
9	**Cost of Capital Rate=**														
10															
11	(a) Weighted Cost of Capital	=		0.1001											
12															
13						Satellite Inv.		Equity AFUDC							
14	(b) Federal Income Tax	=	(	R.O.E. +	(	Tax Credit -w/s 1	+	w/s 10	) /	Satellite Inv. Base)		x	Federal Income Tax Rate	)	
15			(	1								-	Federal Income Tax Rate	)	
16															
17		=	(	0.0786	+(	(7,541)	+	1,583	) /	5,765,498	)	x	0.35	)	
18			(	1								-	0.35	)	
19															
20		=		0.0417559											
21															
22						Satellite Inv.		Eq. AFUDC							
23	(c) State Income Tax	=	(	R.O.E. +	(	(Tax Credit	+	of Deprec. Exp.	) /	Satellite Inv. Base)		+	Federal Income Tax	)*	State Income Tax Rate
24			(	1								-	State Income Tax Rate	)	
25															
26		=	(	0.0786	+(	(7,541)	+	1,583	) /	5,765,498	)	+	0.0417559	)*	0.0893
27			(	1								-	0.0893	)	
28															
29		=		0.0116984											
30															
31															
32															
33	(a)+(b)+(c) **Cost of Capital Rate**	=		0.1535643											
34															
35															
36															
37															

38			**Satellite**	**post 2003 ptf (Incremental Return Calc)**	**Investment Return & Taxes including Incremental Return**	
39						
40	INVESTMENT BASE	$	5,765,498	0		
41						
42	x Cost of Capital Rate		0.1535643	0.0000000		
43						
44	= Investment Return and Income Taxes		885,375	0	885,375	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 12/31/10

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	Local Control Center Plant	18,046,161			18,046,161	Worksheet 6, c.(a) l.17
2						
3	Local Control Center Plant Held for Future Use	209,797	1.0547%	(a)	2,213	Worksheet 11, line 1
4						
5	Local Control Center Accumulated Depreciation	(12,534,636)			(12,534,636)	Worksheet 6, c.(b) l.17
6						
7	Local Control Center Accumulated Deferred Taxes					
8	Accumulated Deferred Taxes (281-283)	(481,758,707)	1.0547%	(a)	(5,081,109)	Worksheet 11, line 3
9	Accumulated Deferred Taxes (190)	162,039,266	1.0547%	(a)	1,709,028	Worksheet 11, line 2
10	Total (line 8+9)	(319,719,441)			(3,372,081)	
11						
12	Unamortized loss on Reacquired Debt	3,799,598	1.0547%	(a)	40,074	Page 111.81c
13						
14	Other Regulatory Assets					
15	FAS 106	12,427,698	4.2840%	(b)	532,403	Page 232.1, lines 4f+8f
16	FAS 109	215,325,236	1.0547%	(a)	2,271,035	Page 232.1, line 17f - Page 278.1.33f
17	Total (line 12+13)	227,752,934			2,803,438	
18						
19	Prepayments	3,628,617	1.0547%	(a)	38,271	Page 111.57d
20						
21	Total Materials and Supplies	6,948,084	1.0547%	(a)	73,281	Worksheet 11, line 4
22						
23	Cash Working Capital					
24	Operation & Maintenance Expense				3,728,205	Worksheet 1, Line 21
25	Administrative & General Expense				1,622,007	Worksheet 1, Line 22
26	Subtotal (line 18+19+20)				5,350,212	
27					0.125	x 45 / 360
28	Total (line 21 * line 22)				668,777	

(a) Worksheet 5, line 37
(b) Worksheet 5, line 11

CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/10

Worksheet 4 of 11

Line No.		(1) Total	(2) Wage/Plant Allocation Factors		(3) = (1)*(2) Local Control Cente Allocated	Worksheet or FERC Form 1 Reference for col (1)
1	Local Control Center Depreciation Expense	922,846			922,846	Worksheet 6, c.d, l. 17
2						
3	Amortization of Loss on Reacquired Debt	711,263	1.0547%	(b)	7,502	Page 117.64c
4						
5	Amortization of Investment Tax Credits	(714,950)	1.0547%	(b)	(7,541)	266.8.f
6						
7	Local Control Center Property Taxes	11,632,496	1.0547%	(b)	122,688	w/s 11, line 5
8						
9	Payroll Taxes (c)	-	4.2840%	(a)	-	
10						
11	Operation and Maintenance					
12	System Control and Load Dispatch - #556	0				Page 321.77b
13	Load Dispatching - #561 - 561.4	3,728,205				Page 321.84b-88b
14	Load Dispatching - #581	0				Page 322.105b
15	Less expenses incurred under ISO Tariff	-				ISO Tariff costs charged to 565
16	O&M - line 12+13+14-15	3,728,205			3,728,205	
17						
18	Administrative and General					
19	A & G subject to Wage & Salaries Allocation Factor	37,797,850	4.2840%	(a)	1,619,260	Worksheet 8, line 29
20	A & G subject to Plant Allocation Factor	260,453	1.0547%	(b)	2,747	Worksheet 8, line 32
21	A & G directly assigned to Local Control Center	-	100.0000%		-	Worksheet 8, lines 15& 18
22	A&G (lines 19+20+21)	38,058,303			1,622,007	

(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 12/31/10

Worksheet 5 of 11

Line No.			Sch. 1 Rate Worksheet or FERC Form 1 Reference
1			
2	**Wages and Salaries Allocation Factor**	2010	
3			
4	Total Local Control Center Direct Wages and Salaries	2,076,092	worksheet 7, c.(d),l.5
5			
6	Total Wages and Salaries	52,898,584	Page 354.25b
7	Administrative and General Wages and Salaries	4,436,763	Page 354.24b
8	Affiliated Company Wages and Salaries less A&G	-	
9	Total Wages and Salaries net of A&G (line 6-7)	48,461,821	
10			
11	Percent Allocation (lines 4 / 9)	**4.2840%**	
12			
13			
14	**Local Control Center Wages and Salaries Allocation Factor**		
15			
16	Total Transmission Local Control Center Direct Wages and Salaries	2,076,092	worksheet 7, c.(d),l.2
17			
18	Total Local Control Center Direct Wages and Salaries	2,076,092	worksheet 5, l.4
19			
20	Percent Allocation (lines 16/18)	**100.0000%**	
21			
22			
23	**Local Control Center PTF Allocation Factor**		
24			
25	Total Local Control Center PTF Direct Wages and Salaries	1,227,038	worksheet 7, c.(e),l.2
26			
27	Total Transmission Local Control Center Direct Wages and Salaries	2,076,092	worksheet 5, l.4
28			
29	Percent Allocation (line 25/27)	**59.1032%**	
30			
31			
32	**Local Control Center Plant Allocation Factor**		
33			
34	Total Investment in Local Control Center Plant	18,046,161	worksheet 6, c.(a),l.17
35	Total Plant in Service	1,711,090,852	Page 207.104g
36			
37	Percent Allocation (lines 34/35)	**1.0547%**	

CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/10

Worksheet 6 of 11

		/---------------12/31/10--------------/			
1	PROPERTY DESCRIPTION	COST	RESERVE	2010 DEPRECIATION	ref
2		(a)	(b)	©	
3	FURNITURE & EQUIPMENT	266,008	131,948	10,450	Fixed Assets
4	STRUCTURE COSTS & MAP BOARDS	3,750,352	1,546,214	91,884	Fixed Assets
5	UPS	284,858	180,928	10,550	Fixed Assets
6	EMS SYSTEM	-	-	-	Fixed Assets
7	EMS HARDWARE	1,466,475	1,041,609	162,925	Fixed Assets
8	EMS SOFTWARE	7,900,188	7,861,832	497,235	Fixed Assets
9	EMS SOFTWARE				Fixed Assets
10	LMS	-	-	-	Fixed Assets
11	S/S & GEN STA. RTUs & SCADA	3,563,016	1,135,688	90,125	Fixed Assets
12	EBCC	-	-	-	Fixed Assets
13	COMMUNICATION EQUIPMENT	815,265	606,383	59,677	Fixed Assets
14	PC EQUIPMENT	-	30,034	-	Fixed Assets
15					
16					
17	TOTALS	18,046,161	12,534,636	922,846	

CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/10

Worksheet 7 of 11

	FERC ACCT	TOTAL EXPENSE	P/R OH & OTHER EXPENSES	SALARIES & WAGES	PTF SALARIES & WAGES	NON-PTF SALARIES & WAGES
		(a)	(b)	©	(d)	(e)
1	561.1 Load Dispatch-Reliability	$ 608,339	$ 224,794	$ 383,545	226,688	156,857
2	561.2 Load Dispatch-Monitor & Operate Transmission System	3,106,379	1,413,832	1,692,547	1,000,350	692,197
	561.3 Load Dispatch-Transmisssion Service & Scheduling	13,487	13,487	-	-	-
3	561.4 Scheduling, System Control & Dispatch Services	-	-	-	-	-
4						
5	TOTAL	$ 3,728,205	$ 1,652,113	$ 2,076,092	1,227,038	849,054
6						

CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/10

Worksheet 8 of 11

	Acc't	Description	Amount	
1	920	Administrative and General Salaries	6,603,794	
2	921	Office Supplies and Expenses	2,761,740	
3	922	Less Administrative Expenses Transferred	(573,663)	
4	923	Outside Services	16,998,968	
5	924	Property Insurance	260,453	
6	925	Injuries and Damages	1,645,480	
7	926	Employee Pensions and Benefits	2,006,284	
8	928	Regulatory Commissions Expense	4,951,869	
9	930.1	General Advertising	1,127,186	
10	930.2	Miscellaneous General Expense	6,038,781	
11	931	Rents	700,578	
12	935	Maintenance of General Plant	1,615,888	
13		Total Admin & Gen'l Exp.	44,137,358	Page 323.197b
14		FERC assessments - Transmission (directly assigned)	968,672	
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)	968,672	FF1 page 350.d
18		State assessments - Satellite (directly assigned)	-	to worksheet 4, line 21
19		Total State Assessments	3,983,197	FF1 page 350.d
	928	Total Regulatory Commissions Expense: (16+18) & from line 8	4,951,869	FF1 page 350.d
20				
21		General Advertising - Transmission related	-	
22		Non-Satellite related General Advertising Exp.	1,127,186	
	930.1	Total General Advertising Exp. (line 9)	1,127,186	
23		**Summary of Schedule 1 Treatment of A&G**		
24		Total A&G (line 13)	44,137,358	
25	924	less Property Insurance (line 5)	(260,453)	
26	928	less Regulatory Commissions Exp. (line 19)	(4,951,869)	
27	930.1	less Non-Trans. General Advertising Exp. (line 9)	(1,127,186)	
28	920-935	less EPRI Expenses	-	
29		A&G subject to Wages and Salaries Allocation Factor:	37,797,850	to ws 4, line 19, col. 1
30		Property Insurance (line 5)	260,453	
31		Regulatory Commissions Exp. - FERC assessments (line 15)	-	
32		Total A&G subject to Plant Allocation Factor	260,453	to ws 4, line 20, col. 1

CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/10

Worksheet 9 of 11

			CAPITALIZATION 12/31/10	CAPITALIZATION RATIOS	COST OF CAPITAL	ANNUAL INTEREST	COST OF CAPITAL	EQUITY PORTION
1	MED-TERM NOTES	page 123.5	443,200,000	31.015%	6.697%	29,681,422		
2	POLLUTION CONTROL NOTES	page 123.5	19,500,000	1.365%	5.594%	1,090,895		
3	FAME	page 123.5	-	0.000%	0.000%	-		
4	MORTGAGE BONDS	page 123.5	-	0.000%	0.000%	-		
5	TOTAL LONG-TERM DEBT		462,700,000	32.380%	6.648%	30,772,318	2.153%	
6	PREFERRED STOCK	page 123.6 and page 112.3d	2,660,500	0.186%	5.062%		0.009%	0.009%
7	COMMON EQUITY	page 112.14d less line 3d	963,604,143	67.434%	11.640%		7.849%	7.849%
8								
9	TOTAL INVESTMENT RETURN		1,428,964,643	100.00%			10.011%	7.858%

10

11

12 Capitalization excludes short term debt(i.e. Revolving Credit Agreement)

13

CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
Source: USS
FOR THE TEST YEAR ENDED 12/31/10

	Vintage	Cost	AFUDC	% of Total
	Transmission Assets:			
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%
	2008	84,332,796	3,500,923	4.15%
39	2009	44,549,845	355,246	0.80%
	2010	20,636,193	558,551	2.71%
40	totals	451,257,947	7,928,201	**1.76%**

41

42 Transmission Plant related Depreciation Expense: $ 90,125 From Worksheet 6, line 11

43

44 AFUDC Adjustment **1,583** To Worksteet 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 12/31/10

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 10	4,062,143	3,852,346	209,797	w/s 3, line 3
	Accumulated Deferred Income Taxes:						
2		190	Page 234.8c	188,213,145	26,173,879	162,039,266	w/s 3, line 9
		282	Page 113.63c	(335,493,003)	51,316,005	(284,176,998)	
		283	Page 113.64c	(221,141,991)	23,560,282	(197,581,709)	
3	subtotal 281-283			(556,634,994)	74,876,287	(481,758,707)	w/s 3, line 8
4	Materials & Supplies		Page 227.11c	10,220,642	3,272,558	6,948,084	w/s 3, line 21
5	Property Taxes		Page 263.14 i	16,797,831	5,165,335	11,632,496	w/s 4, line 7

Local Control Center Support Revenues & Rents:

	MEPCO	$ (191,684)	
	BHE	(311,761)	
	Microwave	(32,792)	
6	Total LCC Revenue	$ (536,237)	w/s 1 line 24

NSTAR Electric Company
Annual Schedule 1 Revenue Requirements - Dispatch Center
Cost Year: 2010
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	3,523,261	Sheet 3, Line 2(f)
4	Dispatch Center Plant Held for Future Use	A.1.c	-	Sheet 3, Line 3(f)
5	Total Plant		$ 14,794,012	Sum Lines 2 thru 4
6	Dispatch Center Related Depreciation Reserve	A.1.d	(4,864,201)	Sheet 3, Line 7(f)
7	Dispatch Center Related Accumulated Deferred Taxes	A.1.e	(3,027,513)	Sheet 3, Line 13(f)
8	Total Net Plant		$ 6,902,298	Sum Lines 5 thru 7
9	Other Regulatory Assets	A.1.f	101,805	Sheet 3, Line 18(f)
10	Dispatch Center Prepayments	A.1.g	510,780	Sheet 3, Line 20(f)
11	Disptach Center Materials & Supplies	A.1.h	7,476	Sheet 3, Line 21(f)
12	Dispatch Center Related Cash Working Capital	A.1.i	683,844	Sheet 3, Line 25(f)
13	**Total Dispatch Center Investment Base**		**$ 8,206,202**	Sum Lines 8 thru 12
14	**Revenue Requirements**			
15	Investment Return and Income Taxes	A.2	$ 1,080,243	Sheet 2, Line 38(c)
16	Disptach Center Depreciation Expense	B	472,959	Sheet 4, Line 4(f)
17	Dispatch Center Related Amortization of Investment Tax Credits	C	(3,845)	Sheet 4, Line 5(f)
18	Dispatch Center Related Municipal Tax Expense	D	255,423	Sheet 4, Line 6(f)
19	Dispatch Center Related Payroll Tax Expense	E	209,709	Sheet 4, Line 24(f)
20	Dispatch Center Operation & Maintenance Expense	F	2,797,621	Sheet 4, Line 13(f)
21	Dispatch Center Related Administrative and General Expenses	G	2,673,130	Sheet 4, Line 23(f)
22	Revenues Received from ISO		-	Sheet 5, Line 3(f)
23	**Total Revenue Requirements**		**$ 7,485,238**	Sum Lines 15 thru 22
24	PTF Transmission Plant Allocator		87.5691%	RNS Sheet 6
25	**PTF Revenue Requirement for SCADA**		**$ 6,554,755**	Line 23 * Line 24

NSTAR Electric Company
Investment Return and Income Taxes
Cost Year: 2010
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	1,609,990,151	42.3270%	5.39%	2.2798%		Page 112.24c
3	Preferred Stock	A.2.a.ii	43,000,000	1.1305%	4.56%	0.0515%	0.0515%	Page 112.3c
4	Common Equity	A.2.a.iii	2,150,708,925	56.5426%	11.64%	6.5816%	6.5816%	Page 112.16c (less Line 3)
5	Total		3,803,699,076	100.0000%		8.9129%	6.6331%	Sum Lines 2 thru 4
6	Total Investment Base		8,206,202					Sheet 1, Line 13(c)
7	Weighted Cost of Capital		8.9129%					Line 5, Col (f)
8	Total Return on Investment		**$ 731,411**					Line 6 * Line 7
9	**Federal Income Tax**	A.2.b						
10	A = Equity Cost		6.6331%					Line 5, Col (g)
11	B = Transmission Amortization of ITC		(3,845)					Sheet 4, Line 5(f)
12	C = Equity AFUDC		-					
13	Total B + C		(3,845)					Line 11 + Line 12
14	D = Investment Base		8,206,202					Line 6
15	(B + C) / D		-0.0469%					Line 13 / Line 14
16	(A + [(C + B) / D]		6.5862%					Line 10 + Line 15
17	FT = Federal Income Tax Rate		35.0000%					
18	1 - FT		65.0000%					1 - Line 17
19	Federal Tax Factor		3.5464%					Line 16 * Line 17 / Line 18
20	Total Federal Income Taxes		**$ 291,027**					Line 14 * Line 19
21	**State Income Tax**	A.2.c						
22	A = Equity Cost		6.6331%					Line 5, Col (g)
23	B = Transmission Amortization of ITC		(3,845)					Sheet 4, Line 5(f)
24	C = Equity AFUDC		-					
25	Total B + C		(3,845)					Line 23 + Line 24
26	D = Investment Base		8,206,202					Line 6
27	(B + C) / D		-0.0469%					Line 25 / Line 26
28	(A + [(C + B) / D]		6.5862%					Line 22 + Line 27
29	ST = State Income Tax Rate		6.5000%					
30	1 - ST		93.5000%					1 - Line 29
31	Federal Tax Factor		3.5464%					Line 22
32	State Tax Factor		0.7044%					(Line 28 + Line 31) * Line 29 / Line 30
33	Total State Income Taxes		**$ 57,805**					Line 26 * Line 32
34	**Investment Return and Income Taxes**	A.2						
35	Return on Investment		731,411					Line 8
36	Federal Income Taxes		291,027					Line 20
37	State Income Taxes		57,805					Line 33
38	**Total Investment Return and Income Taxes**		**$ 1,080,243**					Sum Lines 35 thru 37
39	**Value of 50BP ROE Adder**							
40	ROE Adder		0.5000%					Per Tariff
41	Equity Ratio		56.5426%					Line 4, Col (d)
42	Effective Adder		0.2827%					Line 40 * Line 41
43	Tax Gross-up		0.1825%					Line 19 * .645413
44	Adder plus Gross-up		0.4652%					Line 42 + Line 43
45	Rate Base		$ 8,206,202					Line 6
46	Earned Adder		$ 38,174					Line 44 * Line 45
47	PTF Ratio		87.57%					RNS Sheet 6
48	**PTF Related Adder**		$ 33,428					Line 46 * Line 47

NSTAR Electric Company
Dispatch Center Investment Base
Cost Year: 2010
Sheet 3

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line	Description	Tariff Section	Total	Allocator	Allocation Factor	Dispatch Center Allocated	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	184,521,250	W&S	1.9094%	3,523,261	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		(3,595,719)	Direct	100.0000%	(3,595,719)	FF1 219.25b (part)
6	Transmission Related General Depreciation Reserve		(66,433,323)	W&S	1.9094%	(1,268,482)	FF1 219.28b
7	Total Dispatch Center Related Depreciation Reserve		(70,029,042)			(4,864,201)	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	0.2730%	-	FF1 273.17k
10	Accumulated Deferred Income Taxes - Other Property (Acct #282)		(602,787,456)	Plant	0.2730%	(1,645,870)	Line 28
11	Accumulated Deferred Income Taxes - Other (Acct #283)		(580,752,748)	Plant	0.2730%	(1,585,706)	Line 29
12	Less Accumulated Deferred Income Taxes (Acct #190)		74,736,516	Plant	0.2730%	204,063	Page 234.18c
13	Total Dispatch Center Related Accumulated Deferred Taxes		(1,108,803,688)			(3,027,513)	Sum Lines 9 thru 12
14	**Other Regulatory Assets**	A.1.f					
15	FAS 106		1,546,517	W&S	1.9094%	29,529	FF1 232.1.33f
16	ASC 740 Regulatory Asset (FAS 109)		32,986,993	Plant	0.2730%	90,069	FF1 232.1.23f
17	ASC 740 Regulatory Liability (FAS 109)		(6,516,564)	Plant	0.2730%	(17,793)	FF1 278.2f
18	Total Other Regulatory Assets		28,016,946			101,805	Sum Lines 15 thru 17
19	**Dispatch Center Prepayments**	A.1.g					
20	Prepayments		26,750,697	W&S	1.9094%	510,780	FF1 111.57c
21	**Dispatch Center Materials and Supplies**	A.1.h	2,738,088	N/A	0.2730%	7,476	FF1 227.8c + 5c(footnote)
22	**Dispatch Center Related Cash Working Capital**	A.1.i					
23	Dispatch Center Operation and Maintenance Expense		2,797,621	WC	12.5000%	349,703	Sheet 4, Line 13(f)
24	Dispatch Center Related Administrative and General Expense		2,673,130	WC	12.5000%	334,141	Sheet 4, Line 23(f)
25	Total Dispatch Center Related Cash Working Capital		5,470,751			683,844	Line 23 + Line 24
26	(d) Account 282		602,787,456	FF1 275.9k			
27	less amounts related to divestiture		-	FF1 275.4k			
28	Total Account 282		602,787,456	Sum line 26 thru line 27			
29	(e) Account 283		657,515,365	FF1 277.9k			
30	less amounts related to divestiture		(76,762,617)	FF1 277.9k(footnote)			
31	Total Account 283		580,752,748	Sum line 29 thru line 30			

Notes:

Description	Allocation Factor	Reference
Direct Allocation (Direct)	100.0000%	
Wages & Salary Allocation (W&S)	1.9094%	Sheet 6, Line 6(c)
Plant Allocation Allocation (Plant)	0.2730%	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: 2010
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 34
3	General Depreciation		10,337,429	W&S	1.9094%	197,384	FF1 336.10f
4	Total Dispatch Center Depreciation Expense		10,613,004			472,959	Line 2 + Line 3
5	**Dispatch Center Related Amortization of Investment Tax Credits**	C	(1,408,371)	Plant	0.2730%	(3,845)	FF1 266.8f & 11f
6	**Dispatch Center Related Municipal Tax Expense**	D	93,546,588	Plant	0.2730%	255,423	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		1,137,917	Direct	100.0000%	1,137,917	FF1 321.85b
10	Load dispatching - Mon & Oper Trans System 561.2		1,106,469	Direct	100.0000%	1,106,469	FF1 321.86b
11	Load dispatching - Trans Service & Scheduling #561.3		553,235	Direct	100.0000%	553,235	FF1 321.87b
12	Scheduling, System Control and Dispatch Services #561.4		12,321,416		0.0000%	-	FF1 321.88b
13	Total Dispatch Center O&M Expense		15,119,037			2,797,621	Sum Lines 8 thru 12
14	**Dispatch Center Related Administrative & General Expenses**	G					
15	Administrative and General Expenses		149,338,323				FF1 323.197b
16	less Property Insurance (Acct #924)		(559,763)				FF1 323.185b
17	less Regulatory Commission Expenses (Acct #928)		(8,723,785)				FF1 323.189b
18	less General Advertising Expenses (Acct #930.1)		(354,573)				FF1 323.191b
19	Subtotal		139,700,202	W&S	1.9094%	2,667,445	Sum Lines 15 thru 18
20	Property Insurance		559,763	Plant	0.2730%	1,528	FF1 323.185b
21	Transmission Related Regulatory Commission Expenses		1,522,267	Plant	0.2730%	4,156	FF1 350.8d
22	Transmission Related General Advertising Expense		-	Direct	100.0000%	-	
23	Total Dispatch Center Related A&G Expenses		141,782,232			2,673,130	Sum Lines 19 thru 22
24	**Dispatch Center Related Payroll Tax Expense**	E	10,982,922	W&S	1.9094%	209,709	FF1 263.8i

25 **NOTES:**

26	**Description**	**Allocation Factor**	**Reference**
27	Direct Allocation (Direct)	100.0000%	
28	Wages & Salaries Allocation (W&S)	1.9094%	Sheet 6, Line 6(c)
29	Plant Allocation (Plant)	0.2730%	Sheet 6, Line 16(c)

30	**Description**	**Total Investment**	**Life Depr. Rate**	**Depreciation Expense**	**Reference**
31	Mass. Ave. Service Center - 421 (Trans. & Conversion Station Structures)	2,816,142	2.19%	61,674	Sheet 6, Line 9(c)
32	Mass. Ave. Service Center - 431 (Trans. Station Equipment)	7,916,648	2.53%	200,291	Sheet 6, Line 10(c)
33	SCADA Mass. Ave. - 431 (Trans. Station Equipment)	537,962	2.53%	13,610	Sheet 6, Line 11(c)
34	Total	11,270,751		275,575	Sum Lines 31 thru 33

NSTAR Electric Company
Dispatch Center Revenues
Cost Year: 2010
Sheet 5

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line	Description	Tariff Section	Total	Allocator	Allocation Factor	Dispatch Center Allocated	Reference
1	**Revenues received from ISO**						
2	NEPOOL Scheduling & Dispatch Revenue		334,271	Direct		334,271	OATT Schedule 1 TOUT
3	Total Revenues Received from ISO		334,271			334,271	

4 **NOTES:**

5	Description	Allocation Factor	Reference
6	Direct Allocation (Direct)	100.0000%	
7	Wages & Salaries Allocation (W&S)	1.9094%	Sheet 6, Line 6(c)
8	Plant Allocation (Plant)	0.2730%	Sheet 6, Line 16(c)

Credit for NEPOOL Scheduling & Dispatch Revenues in account 456920 is reduced for RTO incentives in accordance with the Company's Regional Scheduling & Dispatch tariff as calculated on Sheet 2, Line 48, Col (c).

NSTAR Electric Company
Allocation Factors
Cost Year: 2010
Sheet 6

	(a)	(b)	(c)	(d)
Line	**Description**	**Tariff Section**	**Amount**	**Reference**
1	**Dispatch Center Wages & Salaries Allocation Factor**	Definitions		
2	Direct Dispatch Center Wages & Salaries		2,306,908	Acct 561 Labor
3	NSTAR Electric Direct Wages & Salaries		159,731,913	FF1 354.28b
4	Administrative & General Wages & Salaries		(38,913,852)	FF1 354.27b
5	Total NSTAR Electric Wages & Salaries net of A&G		120,818,061	Line 3 + Line 4
6	**Wages & Salaries Allocation Factor**		**1.9094%**	Line 2 / Line 5
7	**Dispatch Center Plant Allocation Factor**	Definitions		
8	Dispatch Center Investment			
9	Mass. Ave. Service Center - 421 (Trans. & Conversion Station Structures)		2,816,142	
10	Mass. Ave. Service Center - 431 (Trans. Station Equipment)		7,916,648	
11	SCADA Mass. Ave. - 431 (Trans. Station Equipment)		537,962	
12	Total Dispatch Center Investment		11,270,751	Sum Lines 9 thru 11
13	Dispatch Center Related General Plant Investment		3,523,261	Sheet 3, Line 2(f)
14	Total Dispatch Center Plant Investment		14,794,012	Line 12 + Line 13
15	Total Plant in Service		5,418,195,054	FF1 207.104g
16	**Plant Allocation Factor**		**0.2730%**	Line 14 / Line 15

Attachment 7

Service List of State Regulators and Other Interested Parties

CT Public Utilities Regulatory Authority
10 Franklin Square
New Britain, CT 06051-2605

Maine Public Utilities Commission
18 State House Station
Augusta, ME 04333-0018

MA Department of Public Utilities
One South Station, 2d Floor
Boston, MA 02110

NH Public Utilities Commission
21 South Fruit Street, Suite 10
Concord, NH 03301-2429

RI Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

Vermont Public Service Board
112 State Street, Drawer 20
Montpelier, VT 05620-2701

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ISO New England, Inc.
One Sullivan Road
Holyoke, MA 01040-2841

Gordon Van Welie
ISO New England, Inc.
One Sullivan Road
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New England Power Pool
c/o David Doot
Day Pitney LLP
City Place I, 185 Asylum St.
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Power Planning Committee
New England Governors Conference, Inc.
76 Summer Street, 2nd Floor
Boston, MA 02110

Clifton C. Below, President
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Commissioners, Inc.
c/o New Hampshire Public Utilities Commission
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Attachment 8

Service List of Participating Transmission Owners

Service List of
Participating Transmission Owners

Bangor Hydro Electric Company

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