Michael J. Hall
Chair - PTO AC Legal Working Group

July 30, 2010

By Fed-Ex Overnight Mail

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, 2010 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 an original and 14 copies of this letter and supporting materials which identify updated rates for regional transmission and scheduling, system control and dispatch services effective as of June 1, 2010 under Section II of the ISO New England Inc. Transmission, Markets and Services Tariff, designated FERC Electric Tariff No. 3 ("ISO Tariff"). The updated charges are based on actual cost data for calendar year 2009 and estimated cost data for calendar year 2010 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 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".

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

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 that will be in effect for the period beginning June 1, 2010 through May 31, 2011. 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 in accordance with the Commission's August 7, 2009 order in Docket No. ER09-938-000[7] the enclosed filing includes forecasted revenue requirements associated with projected capital additions to Pool Transmission Facilities ("PTF") and Maine Power Reliability Program Construction Work In Progress ("MPRP CWIP") and a true-up of the amounts billed in the prior rate year. 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, 2010 and forecasted MPRP CWIP as of December 31, 2010. 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 2008 actual data, plus 2009 forecasted data, and the revenue requirements for 2009 based on actual data.

Pursuant to Attachment F of the ISO Tariff, the annual formula rates have been updated to reflect actual 2009 cost data, Forecasted Transmission Revenue Requirements associated with projected PTF additions and MPRP CWIP for 2010 (i.e. the Forecast Period), and the Annual True-up including associated interest. This annual update results in a Pool RNS Rate of $64.83/kW-year effective June 1, 2010. The new rate represents an increase of $4.88 from the Pool RNS Rate of $59.95/kW-year that went into effect on June 1, 2009.[8] 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 $1.65/kW-year effective June 1, 2010. This represents an increase of $0.13/kW-year over the Schedule 1 charge of $1.52/kW-year based on 2008 data that went into effect as of June 1, 2009.

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[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 Co.,* 128 FERC ¶ 61,143 (2009)

[8] The effective rate on December 1, 2008 reflects the third supplement to the July 31, 2008 Annual Informational Filing Regarding ISO Tariff Charges in Docket No. ER08-1328-001 filed with the Commission on June 30, 2009.

Pursuant to Schedule 9 of the ISO Tariff, actual charges to a Transmission Customer for RNS during an eleven year transition period have been based on the individual Local Network RNS Rate for the applicable Local Network from which the Transmission Customer's load is served. This transition began on March 1, 1997 and concluded on February 29, 2008.[9] March 1, 2008 marked the completion of the eleven year transition and the RNS rate has now become a true "postage stamp" rate for regional network transmission services throughout New England. The following table shows that the Local Network RNS Rates for each applicable PTO for the period commencing June 1, 2010 through May 31, 2011 are equal to the Pool RNS Rate.

Applicable Participating Transmission Owner	Local Network RNS Rate ($/kW-yr) 6/1/10 – 5/31/2011
BHE	64.83
NSTAR	64.83
CMP	64.83
FG&E	64.83
NGRID	64.83
NU	64.83
UI	64.83
VTransco	64.83
Pool RNS Rate	64.83

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, 2010 – May 31, 2011 based on 2009 actual data and 2010 forecasted data[10];
- Attachment 2 - PTOs' Annual Transmission Revenue Requirement calculations pursuant to Attachment F based on 2009 actual data and 2010 forecasted data (including Highgate Transmission Facilities ("HTF"));
- Attachment 3 – Summary of Forecasted Transmission Revenue Requirements associated with projected PTF additions for 2010;
- Attachment 4 – Annual True-up Summary;
- Attachment 5 - Schedule 1 Rates effective June 1, 2010 through May 31, 2011, based on 2009 data;
- Attachment 6 - PTOs' Annual Revenue Requirement calculations pursuant to Schedule 1, based on 2009 data;
- Attachment 7 - Service List of state regulators and other interested parties; and

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[9] The Commission initially approved the transition mechanism as part of the April 5, 1999 comprehensive settlement accepted by the Commission in Docket Nos. OA97-237-007, *et al.*, *New England Power Pool*, 88 FERC ¶ 61,140. Schedule 9 as approved by the Commission in the RTO Orders did not disturb these transition arrangements.

[10] Attachment 1, containing Schedule 9 RNS Rates, in the instant filing has been modified in comparison to prior year Annual Informational Filings in Docket Nos. RT04-2-000, *et al*, to reflect the completion of the eleven year transition period.

- 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.

Please indicate receipt of this filing by date stamping and returning a copy of this filing letter in the enclosed pre-posted, pre-addressed envelope.

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, 2010 – May 31, 2011
Based on 2009 Actual Data, 2010 Forecasted Data and Annual True-up

PTO 2009 12 CP NETWORK LOADS

Local Networks	2009 Network Load (MW)
NSTAR	4,026.458
Bangor Hydro Electric	253.925
Fitchburg Gas & Electric	73.650
Central Maine Power	1,377.442
National Grid	5,437.030
Northeast Utilities	6,776.983
United Illuminating	697.181
VTransco	814.937
Total	**19,457.606**

Long Term TOUT (MW)	0

PTO RNS Rates for 6/1/10	PRE 97 RNS Rate	Post 96 RNS Rate	RNS Rates for June 1, 2010	RNS Rates previously in effect June 1, 2009	Delta
Total NE Rev Req	$296,948,834	$964,426,357			
Total NE Loads - kw	19,457,606	19,457,606			
Total NE RNS $ / kw-yr.	15.26132	49.56552	64.82684	59.94700	4.87984

		PTO 2009 Rev Req				
		PTO Annual Input Data	**2009**			
				PTF Revenue Requirements		
		Company	Power Supplier (if different than Company)	Pre-1997 PTF B1 $	Post-1996 PTF B2 $	
1		**MEPCO**		($1,035,879)	($215,724)	1
2		**NSTAR**		$53,345,884	$91,273,277	2
3		Braintree		$194,674	$2,505,539	3
4		Cambridge (NSTAR Merger)	CES (1)	$0	$0	4
5	*	Concord		$12,316	$0	5
6	*	Hingham		$48,626	$0	6
7	*	Hull		$16,862	$0	7
8	*	Norwood	NEES (1)	$0	$2,490,678	8
9		Quincy/Weymouth	NEES (1)	$0	$0	9
10	*	Reading		$71,176	$206,133	10
11		**Bangor Hydro Electric**		$1,249,219	$35,788,922	11
12		**Commonwealth Energy Systems** (NSTAR Merger)		$0	$0	12
13		**Central Maine Power**		$19,301,201	$67,078,708	13
14		Madison		$0	$0	14
15		Middleborough		$50,287	$0	15
16	*	Pascoag,RI		$9,741	$0	16
17		Taunton		$222,659	$0	17
18		Tiverton	NEES (1)	$0	$0	18
19		**Mass. Mun. Wholsale Elect. Co.**		$0	$0	19
20		**National Grid**		$83,519,745	$118,924,272	20
21		Ashburnham		$7,404	$0	21
22	*	Boylston		$9,038	$0	22
23	*	CVPS		$0	$0	23
24		Danvers		$110,662	$0	24
25	*	French King	NU (1)	$0	$0	25
26		Georgetown		$9,714	$0	26
27	*	GMP		$0	$0	27
28		Groton,MA		$12,508	$0	28
29	*	Holden		$37,551	$0	29
30		Hudson		$134,753	$0	30
31	*	Ipswich		$9,489	$0	31
32	*	Littleton,MA		$17,575	$0	32
33	*	Mansfield		$77,334	$0	33
34	*	Marblehead		$24,456	$0	34
35	*	Middleton		$29,377	$0	35
36	*	N. Attleboro		$43,980	$0	36
37	*	Paxton		$8,523	$0	37
38	*	Peabody		$117,622	$0	38
39	*	Princeton		$0	$0	39
40	*	Rowley		$1,617	$0	40
41	*	Shrewsbury		$65,980	$0	41
42	*	Sterling		$15,153	$0	42
43	*	Templeton		$21,374	$0	43
44	*	Wakefield		$48,310	$0	44
45	*	W.Boylston		$20,541	$0	45
46	*	Fitchburg Gas & Electric		$349,959	$148,543	46
47		**Northeast Utilities**		$97,784,169	$444,115,548	47
48		Bolt Hill	CMP (1)	$0	$0	48
49		Chicopee		$32,331	$0	49
50		Conn. Municipal Electric Energy Co-op		$203,631	$1,111,669	50
51		Holyoke		$1,143,680	$689,266	51
52		SBNG	NEES (1)	$0	$0	52
53		S.Hadley		$55,600	$0	53
54	*	UI S/S	UI (1)	$0	$0	54
55		FPL-NED		$361,521	$9,116,738	55
56		Westfield		$92,700	$0	56
57	*	Unitil		$118,310	$0	57
58		**United Illuminating**		$27,855,701	$90,978,727	58
59		**VTransco**		$11,121,760	$94,475,344	59
60		**New Hampshire Electric Co-op**		$0	$0	60
61		**HTF**		$0	$5,738,717	61
62		**Total**		$296,948,834	$964,426,357	62

***** These systems do not own PTF; revenue requirement amounts indicate payments made to support PTF owned by other Participants.

LOAD VALUE (kW)																		
cal Network	Local Network Name				Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total Annual Network Load	Average Monthly Network Load
Total Network Load (kW)					19,985,252	19,918,061	19,229,978	17,892,692	17,444,293	18,577,604	22,342,597	24,899,114	18,072,787	17,017,498	17,616,527	20,494,755	233,491,158	19,457,606
1	BE				4,131,360	4,008,693	3,825,560	3,808,178	3,732,804	3,886,676	4,783,733	5,282,395	3,863,683	3,402,315	3,499,816	4,092,278	48,317,491	4,026,458
2	BHE				278,604	256,126	257,925	227,173	221,237	242,784	259,147	303,319	241,111	237,864	241,674	280,137	3,047,101	253,925
4	CMP				1,456,271	1,400,416	1,384,511	1,225,150	1,245,310	1,323,409	1,471,573	1,568,240	1,280,247	1,314,419	1,355,167	1,504,586	16,529,299	1,377,442
6	NEP				5,252,098	5,587,534	5,359,541	4,973,212	4,912,844	5,068,569	6,361,995	7,187,633	5,040,006	4,753,740	4,979,381	5,767,767	65,244,320	5,437,030
7	NU				7,208,712	7,059,354	6,827,485	6,230,946	5,957,814	6,475,346	7,688,035	8,609,262	6,138,036	5,908,271	6,056,585	7,163,913	81,323,759	6,776,983
8	UI				701,799	679,193	679,302	626,796	587,082	695,882	841,960	949,900	690,155	596,714	627,662	689,716	8,366,161	697,181
9	VELCO/VT Transco				877,418	849,204	824,505	732,820	720,467	816,748	854,557	911,276	751,437	735,933	787,063	917,805	9,779,233	814,937
15	FGE				78,990	77,541	71,149	68,417	66,735	68,190	81,597	87,089	68,112	68,242	69,179	78,553	883,794	73,650

LOAD VALUE (kW)																		
Total Network Load (kW)					19,985,252	19,918,061	19,229,978	17,892,692	17,444,293	18,577,604	22,342,597	24,899,114	18,072,787	17,017,498	17,616,527	20,494,755	233,491,158	19,457,606
cal Network	Local Network Name	Network Load ID	Duns Number	Network Load Name	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total Annual Network Load	Average Monthly Network Load
1	BE	2	17-057-1897	Braintree	65,605	64,185	60,770	59,636	58,498	59,741	73,562	82,357	57,792	52,592	55,163	66,185	756,086	63,007
1	BE	4	07-952-6729	Concord	32,103	31,380	29,774	31,176	29,745	29,679	36,614	41,249	29,351	26,285	27,292	31,993	376,641	31,387
1	BE	5	14-703-0704	Hingham	33,376	32,396	31,384	31,620	31,448	31,480	41,868	46,972	30,700	28,708	29,336	34,364	403,652	33,638
1	BE	6	13-661-7155	Hull	9,791	9,747	9,640	6,362	6,831	7,186	10,315	12,313	6,735	8,152	8,108	10,007	105,187	8,766
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)	54,315	51,570	47,340	56,925	54,045	55,620	66,465	74,340	55,440	43,695	46,440	53,325	659,520	54,960
1	BE	11	00-695-2626	MECO - Quincy/Wey. (R W)	217,000	212,786	206,902	175,789	168,369	175,894	229,777	254,938	169,119	168,419	172,425	211,020	2,362,438	196,870
1	BE	13	86-703-4654	Reading	77,520	75,200	73,360	78,880	83,200	80,560	96,720	108,320	76,880	66,624	70,644	79,548	967,456	80,621
1	BE	14	17-819-3330	Wellseley	44,539	42,920	41,008	44,315	40,647	40,034	51,225	56,077	39,271	35,265	37,016	44,010	516,327	43,027
1	BE	15	07-382-0680	Belmont (PASNY)	23,343	23,692	23,090	19,031	18,972	18,803	25,340	28,462	18,098	19,671	20,163	23,624	262,289	21,857
2	BHE	16	00-694-9002	Bangor Hydro Electric	272,754	250,577	252,313	223,147	217,400	238,823	254,798	297,953	237,196	232,904	236,420	273,928	2,988,213	249,018
2	BHE	17	00-694-8954	CMP - Herman Sub	5,850	5,549	5,612	4,026	3,837	3,961	4,349	5,366	3,915	4,960	5,254	6,209	58,888	4,907
4	CMP	21	00-694-8954	Central Maine Power	1,384,149	1,328,897	1,312,754	1,155,482	1,168,518	1,247,108	1,394,113	1,503,494	1,212,288	1,246,093	1,284,757	1,427,108	15,664,761	1,305,397
4	CMP	22	11-923-4722	NP - Fox Island	1,674	1,673	1,598	1,383	1,550	1,515	1,692	1,834	1,726	1,609	1,548	1,387	19,189	1,599

					LOAD VALUE (kW)													
cal Network	Local Network Name				Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total Annual Network Load	Average Monthly Network Load
Total Network Load (kW)					19,985,252	19,918,061	19,229,978	17,892,692	17,444,293	18,577,604	22,342,597	24,899,114	18,072,787	17,017,498	17,616,527	20,494,755	233,491,158	19,457,606
1	BE				4,131,360	4,008,693	3,825,560	3,808,178	3,732,804	3,886,676	4,783,733	5,282,395	3,863,683	3,402,315	3,499,816	4,092,278	48,317,491	4,026,458
2	BHE				278,604	256,126	257,925	227,173	221,237	242,784	259,147	303,319	241,111	237,864	241,674	280,137	3,047,101	253,925
4	CMP				1,456,271	1,400,416	1,384,511	1,225,150	1,245,310	1,323,409	1,471,573	1,568,240	1,280,247	1,314,419	1,355,167	1,504,586	16,529,299	1,377,442
6	NEP				5,252,098	5,587,534	5,359,541	4,973,212	4,912,844	5,068,569	6,361,995	7,187,633	5,040,006	4,753,740	4,979,381	5,767,767	65,244,320	5,437,030
7	NU				7,208,712	7,059,354	6,827,485	6,230,946	5,957,814	6,475,346	7,688,035	8,609,262	6,138,036	5,908,271	6,056,585	7,163,913	81,323,759	6,776,983
8	UI				701,799	679,193	679,302	626,796	587,082	695,882	841,960	949,900	690,155	596,714	627,662	689,716	8,366,161	697,181
9	VELCO/VT Transco				877,418	849,204	824,505	732,820	720,467	816,748	854,557	911,276	751,437	735,933	787,063	917,805	9,779,233	814,937
15	FGE				78,990	77,541	71,149	68,417	66,735	68,190	81,597	87,089	68,112	68,242	69,179	78,553	883,794	73,650

					LOAD VALUE (kW)													
Total Network Load (kW)					19,985,252	19,918,061	19,229,978	17,892,692	17,444,293	18,577,604	22,342,597	24,899,114	18,072,787	17,017,498	17,616,527	20,494,755	233,491,158	19,457,606
cal Network	Local Network Name	Network Load ID	Duns Number	Network Load Name	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total Annual Network Load	Average Monthly Network Load
4	CMP	23	05-448-1341	NP - Kennebunk	16,874	16,824	16,739	14,397	13,538	13,424	16,075	18,255	13,842	14,250	15,360	17,083	186,661	15,555
4	CMP	24	05-448-1341	FPL-Madison	44,390	45,060	35,770	45,760	50,360	52,930	50,940	36,840	44,840	44,240	43,890	48,460	543,480	45,290
6	NEP	31	00-695-2881	New England Power	189	187	182	58	44	59	53	36	27	61	114	144	1,154	96
6	NEP	32	00-695-2261	Granite St. Elec.(R W)	135,125	142,611	137,427	139,466	141,860	148,227	167,007	188,535	129,837	125,726	130,901	149,231	1,735,953	144,663
6	NEP	34	00-119-3655	Narragansett Electric	1,169,031	1,247,520	1,200,500	1,083,816	1,082,822	1,136,551	1,506,822	1,700,563	1,150,498	1,070,772	1,135,448	1,283,824	14,768,167	1,230,681
6	NEP	35	83-729-7852	Ashburnham	5,324	6,328	6,187	4,215	4,141	4,464	5,164	5,738	5,268	5,487	5,704	6,429	64,449	5,371
6	NEP	36	00-695-1552	Boston Edison Co.	41,376	44,383	43,897	46,420	45,210	44,907	51,930	55,996	45,043	41,841	43,068	45,540	549,611	45,801
6	NEP	37	XX-040-0000	Boylston	5,000	5,675	5,463	4,596	4,002	4,143	5,484	6,421	4,627	4,506	4,728	5,816	60,461	5,038
6	NEP	38	96-258-1922	VELCO - Central Vt Pub. Ser.	9,027	9,565	8,980	6,437	7,340	8,884	9,099	10,400	7,894	8,241	8,814	10,404	105,085	8,757
6	NEP	39	15-596-9157	Danvers	53,856	55,152	52,531	54,576	55,613	56,218	66,096	74,390	51,293	46,426	48,269	57,514	671,934	55,995
6	NEP	41	00-695-6551	NU - French King	8,933	10,054	9,828	6,623	6,439	7,245	7,731	8,845	4,159	8,242	7,859	9,941	95,899	7,992
6	NEP	42	15-596-9983	Georgetown	7,935	9,051	9,040	7,423	7,856	7,919	10,459	11,592	8,001	7,979	8,568	9,793	105,616	8,801
6	NEP	44	15-601-8301	Groton MA	11,667	13,474	13,758	11,280	11,358	10,841	13,629	15,849	11,332	11,435	11,796	13,577	149,996	12,500

LOAD VALUE (kW)																		
cal Network	Local Network Name				Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total Annual Network Load	Average Monthly Network Load
Total Network Load (kW)					19,985,252	19,918,061	19,229,978	17,892,692	17,444,293	18,577,604	22,342,597	24,899,114	18,072,787	17,017,498	17,616,527	20,494,755	233,491,158	19,457,606
1	BE				4,131,360	4,008,693	3,825,560	3,808,178	3,732,804	3,886,676	4,783,733	5,282,395	3,863,683	3,402,315	3,499,816	4,092,278	48,317,491	4,026,458
2	BHE				278,604	256,126	257,925	227,173	221,237	242,784	259,147	303,319	241,111	237,864	241,674	280,137	3,047,101	253,925
4	CMP				1,456,271	1,400,416	1,384,511	1,225,150	1,245,310	1,323,409	1,471,573	1,568,240	1,280,247	1,314,419	1,355,167	1,504,586	16,529,299	1,377,442
6	NEP				5,252,098	5,587,534	5,359,541	4,973,212	4,912,844	5,068,569	6,361,995	7,187,633	5,040,006	4,753,740	4,979,381	5,767,767	65,244,320	5,437,030
7	NU				7,208,712	7,059,354	6,827,485	6,230,946	5,957,814	6,475,346	7,688,035	8,609,262	6,138,036	5,908,271	6,056,585	7,163,913	81,323,759	6,776,983
8	UI				701,799	679,193	679,302	626,796	587,082	695,882	841,960	949,900	690,155	596,714	627,662	689,716	8,366,161	697,181
9	VELCO/VT Transco				877,418	849,204	824,505	732,820	720,467	816,748	854,557	911,276	751,437	735,933	787,063	917,805	9,779,233	814,937
15	FGE				78,990	77,541	71,149	68,417	66,735	68,190	81,597	87,089	68,112	68,242	69,179	78,553	883,794	73,650

LOAD VALUE (kW)																		
Total Network Load (kW)					19,985,252	19,918,061	19,229,978	17,892,692	17,444,293	18,577,604	22,342,597	24,899,114	18,072,787	17,017,498	17,616,527	20,494,755	233,491,158	19,457,606
cal Network	Local Network Name	Network Load ID	Duns Number	Network Load Name	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total Annual Network Load	Average Monthly Network Load
6	NEP	45	15-601-8285	NP - Groveland	5,773	6,442	6,413	5,211	5,664	5,773	7,998	8,895	5,703	5,664	5,871	6,934	76,341	6,362
6	NEP	46	87-808-0563	Holden	16,269	17,978	17,979	14,057	13,730	14,297	16,990	20,459	15,614	15,923	16,890	19,337	199,523	16,627
6	NEP	47	10-775-5126	Hudson	53,998	55,412	54,418	57,190	54,852	56,028	64,848	70,840	54,726	50,582	51,130	61,974	685,998	57,167
6	NEP	48	15-586-9563	Ipswich	17,857	19,018	18,441	16,226	17,274	17,294	21,497	25,184	16,677	16,113	16,605	20,178	222,364	18,530
6	NEP	49	79-432-5019	Littleton MA	38,431	38,828	36,859	41,231	40,349	39,450	43,943	48,367	36,461	36,650	37,913	42,578	481,060	40,088
6	NEP	50	09-551-3214	NP - Littleton NH	12,635	12,926	12,352	10,499	10,252	12,387	12,239	13,796	10,870	10,642	11,216	12,951	142,765	11,897
6	NEP	51	95-690-6051	Mansfield	35,942	38,059	36,820	35,813	34,445	34,805	44,424	51,005	35,194	31,767	34,344	38,290	450,908	37,576
6	NEP	53	15-598-9544	Marblehead	18,198	20,403	19,863	13,842	15,876	15,390	20,556	24,588	17,334	16,938	17,739	21,384	222,111	18,509
6	NEP	54	92-933-1452	Massachusetts Development Fin	21,732	22,194	21,497	26,121	23,224	26,297	28,859	30,105	25,599	22,586	23,392	24,118	295,724	24,644
6	NEP	55	78-609-1892	NP - Merrimac	4,884	5,673	5,557	3,840	3,152	4,487	6,081	6,762	4,519	4,526	4,781	6,084	60,346	5,029
6	NEP	56	18-675-8231	Middleton	14,723	14,999	14,532	15,448	16,364	15,889	20,235	22,636	14,801	13,773	14,585	16,433	194,418	16,202
6	NEP	57	13-938-4465	N. Attleboro	38,784	42,576	41,232	34,528	33,600	34,080	44,432	52,080	36,128	33,360	35,792	42,512	469,104	39,092
6	NEP	60	15-582-5391	Paxton	3,705	4,515	4,450	3,137	2,636	2,976	3,579	4,249	3,615	3,897	4,166	4,495	45,420	3,785
6	NEP	61	10-371-6353	Peabody	79,300	82,900	77,800	80,100	82,100	80,900	102,800	116,700	76,700	68,300	72,400	88,000	1,008,000	84,000

LOAD VALUE (kW)

cal Network	Local Network Name				Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total Annual Network Load	Average Monthly Network Load
Total Network Load (kW)					19,985,252	19,918,061	19,229,978	17,892,692	17,444,293	18,577,604	22,342,597	24,899,114	18,072,787	17,017,498	17,616,527	20,494,755	233,491,158	19,457,606
1	BE				4,131,360	4,008,693	3,825,560	3,808,178	3,732,804	3,886,676	4,783,733	5,282,395	3,863,683	3,402,315	3,499,816	4,092,278	48,317,491	4,026,458
2	BHE				278,604	256,126	257,925	227,173	221,237	242,784	259,147	303,319	241,111	237,864	241,674	280,137	3,047,101	253,925
4	CMP				1,456,271	1,400,416	1,384,511	1,225,150	1,245,310	1,323,409	1,471,573	1,568,240	1,280,247	1,314,419	1,355,167	1,504,586	16,529,299	1,377,442
6	NEP				5,252,098	5,587,534	5,359,541	4,973,212	4,912,844	5,068,569	6,361,995	7,187,633	5,040,006	4,753,740	4,979,381	5,767,767	65,244,320	5,437,030
7	NU				7,208,712	7,059,354	6,827,485	6,230,946	5,957,814	6,475,346	7,688,035	8,609,262	6,138,036	5,908,271	6,056,585	7,163,913	81,323,759	6,776,983
8	UI				701,799	679,193	679,302	626,796	587,082	695,882	841,960	949,900	690,155	596,714	627,662	689,716	8,366,161	697,181
9	VELCO/VT Transco				877,418	849,204	824,505	732,820	720,467	816,748	854,557	911,276	751,437	735,933	787,063	917,805	9,779,233	814,937
15	FGE				78,990	77,541	71,149	68,417	66,735	68,190	81,597	87,089	68,112	68,242	69,179	78,553	883,794	73,650

LOAD VALUE (kW)

cal Network	Local Network Name	Network Load ID	Duns Number	Network Load Name	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total Annual Network Load	Average Monthly Network Load
Total Network Load (kW)					19,985,252	19,918,061	19,229,978	17,892,692	17,444,293	18,577,604	22,342,597	24,899,114	18,072,787	17,017,498	17,616,527	20,494,755	233,491,158	19,457,606
6	NEP	62	96-152-2786	NP - Princeton	2,647	3,395	1,869	1,713	1,870	1,854	2,465	2,855	2,497	2,856	2,951	3,520	30,492	2,541
6	NEP	63	11-885-5188	Rowley	7,238	7,511	7,238	6,482	7,036	6,975	8,676	10,129	6,592	6,189	6,688	8,094	88,848	7,404
6	NEP	64	78-451-8870	Shrewsbury	47,460	52,510	50,375	44,820	44,521	42,209	54,818	60,034	45,051	42,279	44,172	52,503	580,752	48,396
6	NEP	65	15-586-0620	Sterling	8,406	9,259	9,283	8,429	8,060	8,662	9,469	11,818	8,383	8,437	8,889	10,101	109,196	9,100
6	NEP	66	02-619-2302	Templeton	9,279	10,257	9,908	7,711	7,817	8,301	8,623	9,394	8,523	8,906	9,254	10,483	108,456	9,038
6	NEP	67	15-415-7622	Wakefield	30,441	31,652	30,677	29,803	29,685	30,123	38,170	43,899	28,207	26,678	28,375	34,155	381,865	31,822
6	NEP	68	12-787-0350	W.Boylston	9,203	10,009	9,606	8,880	8,306	8,195	10,100	11,814	8,155	8,074	8,639	10,403	111,384	9,282
7	NU	70	00-694-8954	CMP - Bolt Hill	39,824	33,815	36,386	21,080	38,004	25,529	45,286	50,837	37,162	36,967	35,977	43,005	443,872	36,989
7	NU	71	11-468-3899	Chicopee	75,600	74,500	71,100	60,900	54,300	64,000	76,400	83,564	60,203	57,523	57,310	64,457	799,857	66,655
7	NU	72	96-165-7079	Conn. Mun. Elec. Enr. Co	301,033	300,704	278,278	263,967	261,722	289,757	322,430	365,053	248,817	247,623	248,841	279,923	3,408,148	284,012
7	NU	73	08-465-0050	Holyoke	58,229	55,902	54,768	54,679	50,488	58,743	63,738	72,106	52,273	49,266	51,050	57,939	679,181	56,598
7	NU	74	00-695-2626	Mass Elec - SBNG (R W)	96,421	90,889	84,400	74,951	73,307	79,498	93,760	102,332	74,571	72,725	73,358	100,111	1,016,323	84,694
7	NU	76	19-548-8630	S.Hadley	21,032	21,100	20,253	18,144	16,307	17,546	22,386	25,198	18,056	17,647	18,038	21,985	237,692	19,808
7	NU	77	00-691-7967	UI S/S	227,558	219,890	215,064	192,559	176,525	218,098	271,032	298,810	203,746	188,031	190,458	217,115	2,618,886	218,241

LOAD VALUE (kW)																		
cal Network	Local Network Name				Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total Annual Network Load	Average Monthly Network Load
Total Network Load (kW)					19,985,252	19,918,061	19,229,978	17,892,692	17,444,293	18,577,604	22,342,597	24,899,114	18,072,787	17,017,498	17,616,527	20,494,755	233,491,158	19,457,606
1	BE				4,131,360	4,008,693	3,825,560	3,808,178	3,732,804	3,886,676	4,783,733	5,282,395	3,863,683	3,402,315	3,499,816	4,092,278	48,317,491	4,026,458
2	BHE				278,604	256,126	257,925	227,173	221,237	242,784	259,147	303,319	241,111	237,864	241,674	280,137	3,047,101	253,925
4	CMP				1,456,271	1,400,416	1,384,511	1,225,150	1,245,310	1,323,409	1,471,573	1,568,240	1,280,247	1,314,419	1,355,167	1,504,586	16,529,299	1,377,442
6	NEP				5,252,098	5,587,534	5,359,541	4,973,212	4,912,844	5,068,569	6,361,995	7,187,633	5,040,006	4,753,740	4,979,381	5,767,767	65,244,320	5,437,030
7	NU				7,208,712	7,059,354	6,827,485	6,230,946	5,957,814	6,475,346	7,688,035	8,609,262	6,138,036	5,908,271	6,056,585	7,163,913	81,323,759	6,776,983
8	UI				701,799	679,193	679,302	626,796	587,082	695,882	841,960	949,900	690,155	596,714	627,662	689,716	8,366,161	697,181
9	VELCO/VT Transco				877,418	849,204	824,505	732,820	720,467	816,748	854,557	911,276	751,437	735,933	787,063	917,805	9,779,233	814,937
15	FGE				78,990	77,541	71,149	68,417	66,735	68,190	81,597	87,089	68,112	68,242	69,179	78,553	883,794	73,650
LOAD VALUE (kW)																		
Total Network Load (kW)					19,985,252	19,918,061	19,229,978	17,892,692	17,444,293	18,577,604	22,342,597	24,899,114	18,072,787	17,017,498	17,616,527	20,494,755	233,491,158	19,457,606
cal Network	Local Network Name	Network Load ID	Duns Number	Network Load Name	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total Annual Network Load	Average Monthly Network Load
7	NU	79	11-923-4722	NP - Chester	1,090	1,152	1,130	528	587	622	766	958	699	863			8,395	700
7	NU	79	12-757-5165	NP - Chester											917	1,131	2,048	171
7	NU	80	12-757-5165	Westfield	59,180	57,809	57,682	59,221	54,328	60,899	69,491	78,292	56,297	51,678	54,368	61,001	720,246	60,021
8	UI	81	00-691-7967	United Illuminating	699,128	671,677	662,922	609,476	578,446	690,009	837,146	943,773	681,273	591,197	607,198	685,448	8,257,693	688,141
9	VELCO/VT	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	134,650	131,980	122,329	76,720	85,980	90,496	112,981	122,407	98,823	103,737	107,744	158,341	1,346,188	112,182
8	UI	84	00-691-7090	NU - Hosley Substation	2,671	3,052	3,420	3,352	3,164	3,137	1,790	3,103	3,986	2,061	3,310	1,268	34,314	2,860
6	NEP	85	00-881-9492	New Hampshire Electric Co-op	1,821	2,096	2,099	1,178	1,248	1,457	1,521	1,671	1,642	1,838	1,855	2,275	20,701	1,725
4	CMP	89	84-173-9824	NP - Gates Formed Fibre	633	1,360	1,429	1,347	2,019	2,075	1,885	2,000	1,429	1,257	2,028	2,098	19,560	1,630
6	NEP	91	86-703-4654	North Reading	28,913	32,299	31,396	31,904	29,856	32,299	42,008	48,639	30,313	27,527	29,002	33,634	397,790	33,149
7	NU	94	00-697-1352	Citizens Utilites	3,047	2,845	2,456	2,088	971	131	143	154	1	169	210	247	12,462	1,039
7	NU	95	11-923-4722	Ashland	3,709	3,729	3,287	2,238	2,398	1,872	2,722	2,747	2,399	2,470	2,617	3,476	33,664	2,805
7	NU	96	11-923-4722	New Hampton	633	538	646	398	327	370	456	464	466	448	571	513	5,830	486

LOAD VALUE (kW)																		
cal Network	Local Network Name				Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total Annual Network Load	Average Monthly Network Load
Total Network Load (kW)					19,985,252	19,918,061	19,229,978	17,892,692	17,444,293	18,577,604	22,342,597	24,899,114	18,072,787	17,017,498	17,616,527	20,494,755	233,491,158	19,457,606
1	BE				4,131,360	4,008,693	3,825,560	3,808,178	3,732,804	3,886,676	4,783,733	5,282,395	3,863,683	3,402,315	3,499,816	4,092,278	48,317,491	4,026,458
2	BHE				278,604	256,126	257,925	227,173	221,237	242,784	259,147	303,319	241,111	237,864	241,674	280,137	3,047,101	253,925
4	CMP				1,456,271	1,400,416	1,384,511	1,225,150	1,245,310	1,323,409	1,471,573	1,568,240	1,280,247	1,314,419	1,355,167	1,504,586	16,529,299	1,377,442
6	NEP				5,252,098	5,587,534	5,359,541	4,973,212	4,912,844	5,068,569	6,361,995	7,187,633	5,040,006	4,753,740	4,979,381	5,767,767	65,244,320	5,437,030
7	NU				7,208,712	7,059,354	6,827,485	6,230,946	5,957,814	6,475,346	7,688,035	8,609,262	6,138,036	5,908,271	6,056,585	7,163,913	81,323,759	6,776,983
8	UI				701,799	679,193	679,302	626,796	587,082	695,882	841,960	949,900	690,155	596,714	627,662	689,716	8,366,161	697,181
9	VELCO/VT Transco				877,418	849,204	824,505	732,820	720,467	816,748	854,557	911,276	751,437	735,933	787,063	917,805	9,779,233	814,937
15	FGE				78,990	77,541	71,149	68,417	66,735	68,190	81,597	87,089	68,112	68,242	69,179	78,553	883,794	73,650

LOAD VALUE (kW)																		
Total Network Load (kW)					19,985,252	19,918,061	19,229,978	17,892,692	17,444,293	18,577,604	22,342,597	24,899,114	18,072,787	17,017,498	17,616,527	20,494,755	233,491,158	19,457,606
cal Network	Local Network Name	Network Load ID	Duns Number	Network Load Name	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total Annual Network Load	Average Monthly Network Load
4	CMP	97	05-448-1341	FPL Energy	2,534	866	10,576	2,479	4,940	2,354	2,255	1,197	2,027	2,217	2,341	2,551	36,337	3,028
6	NEP	98	04-661-6033	Taunton	105,300	110,450	106,760	97,840	96,510	97,670	132,820	150,280	102,110	95,290	99,650	111,490	1,306,170	108,848
6	NEP	99	XX-XXX-0001	NP - MBTA - EUA	353	456	446	69	66	68	73	70	183	201	201	447	2,633	219
6	NEP	100	15-597-6665	Middleboro	42,407	40,784	39,382	32,938	32,498	34,427	49,389	55,958	37,978	36,752	37,904	42,918	483,335	40,278
6	NEP	101	06-984-9461	Pascoag	8,419	9,358	8,991	7,252	7,167	7,648	9,627	11,075	8,319	8,510	8,347	9,726	104,439	8,703
6	NEP	102	00-697-1352	Public Service of NH	0	0	1,956	0	0	1,449	0	0	0	0	0	0	3,405	284
6	NEP	103	01-821-3640	ANP Bellingham	0	0	2,000	0	0	0	0	0	0	0	0	0	2,000	167
4	CMP	105	16-966-8212	Westbrook Energy Center	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	UI	106	84-878-4257	PSEG - Energy Resources & Trading, LLC	0	4,464	12,960	13,968	5,472	2,736	3,024	3,024	4,896	3,456	16,704	0	70,704	5,892
7	NU	108	00-378-9070	Unitil Energy Systems Inc.	207,880	202,601	192,476	180,951	192,467	171,042	232,660	258,218	181,854	170,209	181,280	215,647	2,387,285	198,940
4	CMP	111	05-448-1341	CMP FPL Madison Electric Works	6,017	5,736	5,645	4,302	4,385	4,003	4,613	4,620	4,095	4,753	5,243	5,899	59,311	4,943
9	VELCO/VT	113	00-697-1352	Public Service of New Hampshire	19,762	22,357	21,867	18,281	19,851	21,175	23,525	25,739	19,373	17,844	21,195	23,407	254,376	21,198
7	NU	114	XX-XX5-5555	Town of Wolfeboro Municipal Elec Dept	12,718	12,287	10,934	7,477	9,019	9,291	11,424	12,981	8,955	9,600	10,096	12,834	127,616	10,635
9	VELCO/VT	115	00-881-9492	New Hampshire Electric Co-op	2,721	2,214	2,193	1,250	1,219	1,457	1,683	1,822	1,743	1,836	2,013	2,622	22,773	1,898

LOAD VALUE (kW)																		
cal Network	Local Network Name				Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total Annual Network Load	Average Monthly Network Load
Total Network Load (kW)					19,985,252	19,918,061	19,229,978	17,892,692	17,444,293	18,577,604	22,342,597	24,899,114	18,072,787	17,017,498	17,616,527	20,494,755	233,491,158	19,457,606
1	BE				4,131,360	4,008,693	3,825,560	3,808,178	3,732,804	3,886,676	4,783,733	5,282,395	3,863,683	3,402,315	3,499,816	4,092,278	48,317,491	4,026,458
2	BHE				278,604	256,126	257,925	227,173	221,237	242,784	259,147	303,319	241,111	237,864	241,674	280,137	3,047,101	253,925
4	CMP				1,456,271	1,400,416	1,384,511	1,225,150	1,245,310	1,323,409	1,471,573	1,568,240	1,280,247	1,314,419	1,355,167	1,504,586	16,529,299	1,377,442
6	NEP				5,252,098	5,587,534	5,359,541	4,973,212	4,912,844	5,068,569	6,361,995	7,187,633	5,040,006	4,753,740	4,979,381	5,767,767	65,244,320	5,437,030
7	NU				7,208,712	7,059,354	6,827,485	6,230,946	5,957,814	6,475,346	7,688,035	8,609,262	6,138,036	5,908,271	6,056,585	7,163,913	81,323,759	6,776,983
8	UI				701,799	679,193	679,302	626,796	587,082	695,882	841,960	949,900	690,155	596,714	627,662	689,716	8,366,161	697,181
9	VELCO/VT Transco				877,418	849,204	824,505	732,820	720,467	816,748	854,557	911,276	751,437	735,933	787,063	917,805	9,779,233	814,937
15	FGE				78,990	77,541	71,149	68,417	66,735	68,190	81,597	87,089	68,112	68,242	69,179	78,553	883,794	73,650
LOAD VALUE (kW)																		
Total Network Load (kW)					19,985,252	19,918,061	19,229,978	17,892,692	17,444,293	18,577,604	22,342,597	24,899,114	18,072,787	17,017,498	17,616,527	20,494,755	233,491,158	19,457,606
cal Network	Local Network Name	Network Load ID	Duns Number	Network Load Name	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total Annual Network Load	Average Monthly Network Load
9	VELCO/VT	116	08-910-3543	Vermont Marble	19,915	24,194	18,674	13,942	23,066	30,346	19,190	23,405	23,019	22,658	11,425	29,555	259,389	21,616
9	VELCO/VT	117	14-660-0585	Vermont Electric Cooperative	72,750	64,632	68,020	53,641	52,634	56,851	59,830	55,952	55,047	57,572	63,237	71,912	732,078	61,007
9	VELCO/VT	118	02-065-4430	Burlington Electric Power	46,149	52,119	50,983	54,302	51,171	57,370	58,929	64,099	51,345	45,812	47,942	54,181	634,402	52,867
9	VELCO/VT	119	11-923-4722	Vermont Public Power Supply Authority	84,567	80,185	75,770	57,820	53,964	65,410	64,075	71,060	64,084	67,112	71,317	89,280	844,644	70,387
9	VELCO/VT	120	96-258-1922	Central Vermont Public Service	394,489	368,608	354,534	304,654	296,152	331,427	362,901	387,242	309,930	323,102	337,789	399,067	4,169,895	347,491
9	VELCO/VT	121	03-647-6141	Green Mountain Power	222,295	220,380	219,854	221,835	214,936	242,783	255,377	272,777	219,548	192,410	218,527	231,795	2,732,517	227,710
7	NU	122	00-695-6551	Western Mass Electric Company	618,803	610,635	589,332	569,761	530,826	581,806	654,878	733,526	544,750	517,593	533,607	626,976	7,112,493	592,708
7	NU	123	00-691-7090	Connecticut Light and Power Co.	4,009,406	3,921,948	3,842,263	3,520,717	3,269,926	3,744,620	4,340,852	4,864,757	3,383,062	3,273,795	3,310,558	3,891,058	45,372,962	3,781,080
7	NU	124	00-697-1352	Public Service of New Hampshire	1,333,813	1,311,035	1,237,254	1,117,398	1,135,640	1,057,454	1,363,684	1,531,844	1,162,121	1,100,559	1,171,910	1,403,315	14,926,027	1,243,836
6	NEP	126	16-035-2865	Merrill Lynch Commodities, Inc.	2,331	0	0	0	1,636	0	0	0	0	0	0	0	3,967	331
6	NEP	128	17-160-5301	Dominion Manchester Street	2,632	0	0	0	0	0	0	0	0	0	0	0	2,632	219
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	408	0	0	0	51	383	0	0	0	0	0	0	842	70

					LOAD VALUE (kW)													
cal Network	Local Network Name				Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total Annual Network Load	Average Monthly Network Load
Total Network Load (kW)					19,985,252	19,918,061	19,229,978	17,892,692	17,444,293	18,577,604	22,342,597	24,899,114	18,072,787	17,017,498	17,616,527	20,494,755	233,491,158	19,457,606
1	BE				4,131,360	4,008,693	3,825,560	3,808,178	3,732,804	3,886,676	4,783,733	5,282,395	3,863,683	3,402,315	3,499,816	4,092,278	48,317,491	4,026,458
2	BHE				278,604	256,126	257,925	227,173	221,237	242,784	259,147	303,319	241,111	237,864	241,674	280,137	3,047,101	253,925
4	CMP				1,456,271	1,400,416	1,384,511	1,225,150	1,245,310	1,323,409	1,471,573	1,568,240	1,280,247	1,314,419	1,355,167	1,504,586	16,529,299	1,377,442
6	NEP				5,252,098	5,587,534	5,359,541	4,973,212	4,912,844	5,068,569	6,361,995	7,187,633	5,040,006	4,753,740	4,979,381	5,767,767	65,244,320	5,437,030
7	NU				7,208,712	7,059,354	6,827,485	6,230,946	5,957,814	6,475,346	7,688,035	8,609,262	6,138,036	5,908,271	6,056,585	7,163,913	81,323,759	6,776,983
8	UI				701,799	679,193	679,302	626,796	587,082	695,882	841,960	949,900	690,155	596,714	627,662	689,716	8,366,161	697,181
9	VELCO/VT Transco				877,418	849,204	824,505	732,820	720,467	816,748	854,557	911,276	751,437	735,933	787,063	917,805	9,779,233	814,937
15	FGE				78,990	77,541	71,149	68,417	66,735	68,190	81,597	87,089	68,112	68,242	69,179	78,553	883,794	73,650

					LOAD VALUE (kW)													
Total Network Load (kW)					19,985,252	19,918,061	19,229,978	17,892,692	17,444,293	18,577,604	22,342,597	24,899,114	18,072,787	17,017,498	17,616,527	20,494,755	233,491,158	19,457,606
cal Network	Local Network Name	Network Load ID	Duns Number	Network Load Name	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total Annual Network Load	Average Monthly Network Load
1	BE	133	00-176-6328	Massport	28,432	26,325	26,173	26,900	26,207	26,032	27,356	27,923	25,945	23,375	24,285	26,639	315,592	26,299
1	BE	136	00-695-1552	NSTAR Electric Co. (NEMASS & Boston)	2,584,879	2,505,208	2,378,631	2,569,298	2,455,191	2,531,608	2,963,828	3,258,442	2,500,104	2,132,131	2,198,648	2,540,771	30,618,739	2,551,562
1	BE	137	00-695-1552	NSTAR Electric Co. (SEMASS)	856,242	832,340	796,163	628,136	675,420	742,068	1,050,733	1,188,380	767,889	716,883	735,179	870,182	9,859,615	821,635
1	BE	138	XX-XXX-0001	MBTA - NSTAR (NEMASS & Boston)	61,631	58,588	64,054	45,777	45,668	42,347	55,999	49,091	42,680	47,717	49,316	63,434	626,302	52,192
1	BE	139	XX-XXX-0001	MBTA - NSTAR (SEMASS)	2,393	2,503	2,274	1,388	1,824	1,472	1,359	1,462	1,186	1,377	1,227	1,939	20,404	1,700
6	NEP	140	00-695-2626	Massachusetts Electric (SEMASS)	812,255	866,619	836,510	751,581	746,697	767,982	1,030,519	1,167,098	779,962	736,364	770,817	883,801	10,150,205	845,850
6	NEP	141	00-695-2626	Massachusetts Electric (WCMASS)	1,457,502	1,537,172	1,473,111	1,432,620	1,357,280	1,399,768	1,664,840	1,866,913	1,367,800	1,306,044	1,368,091	1,590,452	17,821,593	1,485,133
6	NEP	142	00-695-2626	Massachusetts Electric (NEMASS & Boston)	805,323	873,273	822,606	749,647	773,760	784,937	970,711	1,109,072	792,278	727,624	750,956	898,756	10,058,943	838,245
6	NEP	143	03-647-6141	Green Mountain Power (New Hampshire)	31,822	35,322	29,739	24,245	23,915	29,251	31,203	37,310	23,738	29,626	29,417	37,892	363,480	30,290
6	NEP	144	03-647-6141	Green Mountain Power (WCMASS)	20,924	21,828	19,903	8,929	9,502	10,514	10,470	11,721	10,812	12,662	16,150	20,985	174,400	14,533
6	NEP	145	XX-XXX-0001	NP MBTA - NEP (SEMASS)	35	44	46	2	2	2	3	3	65	40	32	59	333	28
6	NEP	146	XX-XXX-0001	NP MBTA - NEP (WCMASS)	95	133	122	55	54	52	37	64	124	85	87	99	1,007	84
6	NEP	147	XX-XXX-0001	NP MBTA - NEP (NEMASS & Boston)	7,114	7,100	6,628	4,066	4,227	3,445	4,428	3,555	4,452	4,504	4,105	7,076	60,700	5,058
6	NEP	150	01-426-7137	Transcanada Power Marketing (NH)	0	0	0	0	0	0	0	0	0	0	0	0	0	0

cal Network	Local Network Name				Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total Annual Network Load	Average Monthly Network Load
					LOAD VALUE (kW)													
Total Network Load (kW)					19,985,252	19,918,061	19,229,978	17,892,692	17,444,293	18,577,604	22,342,597	24,899,114	18,072,787	17,017,498	17,616,527	20,494,755	233,491,158	19,457,606
1	BE				4,131,360	4,008,693	3,825,560	3,808,178	3,732,804	3,886,676	4,783,733	5,282,395	3,863,683	3,402,315	3,499,816	4,092,278	48,317,491	4,026,458
2	BHE				278,604	256,126	257,925	227,173	221,237	242,784	259,147	303,319	241,111	237,864	241,674	280,137	3,047,101	253,925
4	CMP				1,456,271	1,400,416	1,384,511	1,225,150	1,245,310	1,323,409	1,471,573	1,568,240	1,280,247	1,314,419	1,355,167	1,504,586	16,529,299	1,377,442
6	NEP				5,252,098	5,587,534	5,359,541	4,973,212	4,912,844	5,068,569	6,361,995	7,187,633	5,040,006	4,753,740	4,979,381	5,767,767	65,244,320	5,437,030
7	NU				7,208,712	7,059,354	6,827,485	6,230,946	5,957,814	6,475,346	7,688,035	8,609,262	6,138,036	5,908,271	6,056,585	7,163,913	81,323,759	6,776,983
8	UI				701,799	679,193	679,302	626,796	587,082	695,882	841,960	949,900	690,155	596,714	627,662	689,716	8,366,161	697,181
9	VELCO/VT Transco				877,418	849,204	824,505	732,820	720,467	816,748	854,557	911,276	751,437	735,933	787,063	917,805	9,779,233	814,937
15	FGE				78,990	77,541	71,149	68,417	66,735	68,190	81,597	87,089	68,112	68,242	69,179	78,553	883,794	73,650

cal Network	Local Network Name	Network Load ID	Duns Number	Network Load Name	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total Annual Network Load	Average Monthly Network Load
					LOAD VALUE (kW)													
Total Network Load (kW)					19,985,252	19,918,061	19,229,978	17,892,692	17,444,293	18,577,604	22,342,597	24,899,114	18,072,787	17,017,498	17,616,527	20,494,755	233,491,158	19,457,606
6	NEP	151	01-426-7137	Transcanada Power Marketing (WCMASS)	76	84	88	73	61	202	70	230	82	156	68	132	1,322	110
1	BE	152	00-799-8644	NP - Nantucket (R W)	24,643	24,322	21,401	13,066	16,589	21,960	30,821	34,692	20,762	18,108	17,782	23,645	267,791	22,316
1	BE	153	05-448-1341	N EA Bellingham	1,325	1,331	1,208	298	0	765	0	0	786	0	0	0	5,713	476
1	BE	154	02-606-6550	MATEP, LLC	14,223	14,200	12,388	19,581	20,150	21,427	21,751	17,377	20,945	13,313	6,792	11,592	193,739	16,145
6	NEP	155	02-825-5979	Somerset Power station service	0	0	2,796	822	816	958	0	0	820	856	838	0	7,906	659
6	NEP	156	78-508-7888	BG Dighton Power station service	0	0	0	0	0	227	0	0	0	459	238	594	1,518	127
7	NU	157	80-693-1007	Milford Power	0	0	0	2,160	0	0	0	0	0	0	0	0	2,160	180
15	FGE	158	00-695-4317	Fitchburg Gas & Electric Light Company	78,990	77,541	71,149	68,417	66,735	68,190	81,597	87,089	68,112	68,242	69,179	78,553	883,794	73,650
7	NU	159	02-825-5979	Devon Off-line Sta. Serv.Load	859	795	689	374	333	356	375	378	347	538	397	795	6,236	520
7	NU	160	02-825-5979	MIddletown Off-line Sta. Serv.Load	531	2,394	2,083	2,195	2,827	1,625	885	3,365	1,780	1,940	2,856	1,613	24,094	2,008
7	NU	161	02-825-5979	Montville Off-line Sta. Serv.Load	18	1,546	1,414	1,085	961	964	677	1,271	913	1,006	1,142	1,364	12,361	1,030
7	NU	162	02-825-5979	Norwalk Harbor Off-line Sta. Serv.Load	2,678	1,260	3,261	1,355	526	627	620	0	741	791	3,280	867	16,006	1,334
7	NU	163	04-042-2193	MP2 Offline Station Service Load	0	0	0	0	0	0	0	0	0	3,093	0	0	3,093	258
7	NU	164	04-042-2193	MP3 Offline Station Service Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0

					LOAD VALUE (kW)													
cal Network	Local Network Name				Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total Annual Network Load	Average Monthly Network Load
Total Network Load (kW)					19,985,252	19,918,061	19,229,978	17,892,692	17,444,293	18,577,604	22,342,597	24,899,114	18,072,787	17,017,498	17,616,527	20,494,755	233,491,158	19,457,606
1	BE				4,131,360	4,008,693	3,825,560	3,808,178	3,732,804	3,886,676	4,783,733	5,282,395	3,863,683	3,402,315	3,499,816	4,092,278	48,317,491	4,026,458
2	BHE				278,604	256,126	257,925	227,173	221,237	242,784	259,147	303,319	241,111	237,864	241,674	280,137	3,047,101	253,925
4	CMP				1,456,271	1,400,416	1,384,511	1,225,150	1,245,310	1,323,409	1,471,573	1,568,240	1,280,247	1,314,419	1,355,167	1,504,586	16,529,299	1,377,442
6	NEP				5,252,098	5,587,534	5,359,541	4,973,212	4,912,844	5,068,569	6,361,995	7,187,633	5,040,006	4,753,740	4,979,381	5,767,767	65,244,320	5,437,030
7	NU				7,208,712	7,059,354	6,827,485	6,230,946	5,957,814	6,475,346	7,688,035	8,609,262	6,138,036	5,908,271	6,056,585	7,163,913	81,323,759	6,776,983
8	UI				701,799	679,193	679,302	626,796	587,082	695,882	841,960	949,900	690,155	596,714	627,662	689,716	8,366,161	697,181
9	VELCO/VT Transco				877,418	849,204	824,505	732,820	720,467	816,748	854,557	911,276	751,437	735,933	787,063	917,805	9,779,233	814,937
15	FGE				78,990	77,541	71,149	68,417	66,735	68,190	81,597	87,089	68,112	68,242	69,179	78,553	883,794	73,650

					LOAD VALUE (kW)													
Total Network Load (kW)					19,985,252	19,918,061	19,229,978	17,892,692	17,444,293	18,577,604	22,342,597	24,899,114	18,072,787	17,017,498	17,616,527	20,494,755	233,491,158	19,457,606
cal Network	Local Network Name	Network Load ID	Duns Number	Network Load Name	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total Annual Network Load	Average Monthly Network Load
9	VELCO/VT	165	02-813-4570	Town of Stowe Electric Dept.	14,770	14,515	12,610	7,095	7,474	9,929	9,047	9,180	7,348	7,587	13,618	15,986	129,159	10,763
7	NU	166	82-524-2444	Waterbury Generation Sta. Srv. Load					45	0	389	0	0	0	0	0	434	36
8	UI	168	05-448-1341	Bridgeport Energy-Station Service												3,000	3,000	250
8	UI	168	88-478-0743	Bridgeport Energy-Station Service										0	450		450	38
6	NEP	169	01-821-3640	ANP Power Milford									0	0	216	259	475	40
6	NEP	170	82-893-7941	L'Energia Montgomery										346	346	432	1,124	94
7	NU	171	00-347-1322	Kleen Energy Station Service Load												200	200	17

Attachment 2

PTOs' Annual Transmission Revenue Requirement Calculations
Pursuant to Attachment F
Based on 2009 Actual Data, 2010 Forecasted Data and Annual True-up

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

Shading denotes an input

Submitted on:	17 May 2010
Revenue Requirements for (year):	Calendar Year 2009
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 =	$1,077,719	(a)	$29,346,529	(f)
Total of Attachment F - Section J - Support Revenue	$0	(b)	$0	(g)
Total of Attachment F - Section K - Support Expense	$159,894	(c)	$0	(h)
Total of Attachment F - Section (L through O)	($39,371)	(d)	($1,022,686)	(i)
Sub Total - Sum (A through I) - J + K + (L through O)	$1,198,243	(e)=(a)-(b)+(c)+(d)	$28,323,843	(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	NA		$5,791,225	(k)
Annual True-up (per Attachment C to Attachment F Implementation Rule)	$50,976	(l)	$1,673,854	(m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)	$1,249,219	(n)=(e)+(l)	$35,788,922	(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).			$37,038,140	(p) = (n) + (o)

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2009
PRE-1997

Shading denotes an input

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	Total	Reference
1	Transmission Plant	(A)(1)(a)	6,437,698	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	113,903	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)		6,551,601	
5	Accumulated Depreciation	(A)(1)(d)	(750,759)	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	(620,914)	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)	(86,175)	Worksheet 3, line 15 column 5
9	Net Investment (Line 4+5+6+7+8)		5,093,753	
10	Prepayments	(A)(1)(h)	16,112	Worksheet 3, line 16 column 5
11	Materials & Supplies	(A)(1)(i)	1,374	Worksheet 3, line 17 column 5
12	Cash Working Capital	(A)(1)(j)	31,708	Worksheet 3, line 24 column 5
13	Total Investment Base (Line 9+10+11+12)		5,142,947	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	788,984	Worksheet 2
15	Depreciation Expense	(B)	133,598	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)	(580)	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	59,428	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	2,519	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	(G)	52,053	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	41,717	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)	159,894	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)	(32,529)	from G/L
28	Transmission Rents Received from Electric Property	(O)	(6,842)	Exhibit: Transmission Rents
29	Total Revenue Requirements (Line 14 thru 28)		1,198,243	

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2009
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)	25,177,695	142,046,950	167,224,644	from GL
2	General Plant	(A)(1)(b)	2,958,715	n/a	2,958,715	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)		28,136,410	142,046,950	170,183,359	
5	Accumulated Depreciation	(A)(1)(d)	(14,867,292)	(4,634,226)	(19,501,518)	from GL / Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	(9,058,917)	(7,069,791)	(16,128,708)	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)	(2,238,452)	n/a	(2,238,452)	Worksheet 3, line 15 column 5
9	Net Investment (Line 4+5+6+7+8)		1,971,749	130,342,933	132,314,681	
10	Prepayments	(A)(1)(h)	418,533	n/a	418,533	Worksheet 3, line 16 column 5
11	Materials & Supplies	(A)(1)(i)	35,696	n/a	35,696	Worksheet 3, line 17 column 5
12	Cash Working Capital	(A)(1)(j)	304,467	n/a	304,467	Worksheet 3, line 24 column 5
13	Total Investment Base (Line 9+10+11+12)		2,730,445	130,342,933	133,073,377	

Line No.	II. REVENUE REQUIREMENTS	Attachment F Reference	Post-96 (less NRI)	NRI	Total	Reference
14	Investment Return and Income Taxes	(A)	20,415,173	1,431,244	21,846,417	Worksheet 2
15	Depreciation Expense	(B)			3,470,311	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)			(15,071)	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)			1,543,695	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)			65,443	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	(G)			1,352,107	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)			1,083,627	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)			(844,956)	from G/L
28	Transmission Rents Received from Electric Property	(O)			(177,730)	Exhibit: Transmission Rents
29	Total Revenue Requirements (Line 14 thru 28)				28,323,843	

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2009
PRE-1997

Shading denotes an input

		CAPITALIZATION 12/31/2009	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	160,909,090	35.26%	7.24%	2.55%	
PREFERRED STOCK		421,800	0.09%	7.00%	0.01%	0.01%
COMMON EQUITY		295,013,249	64.65%	11.64%	7.53%	7.53%
TOTAL INVESTMENT RETURN	$	456,344,139	100.00%		10.09%	7.54%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.1009

(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)

= (0.0754 +((580) + 4,581) / 5,142,947) x 0.35)
(1 - 0.35)

= 0.0410189

(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)

= (0.0754 +((580) + 4,581) / 5,142,947) + 0.0410189)* 0.0893
(1 - 0.0893)

= 0.0114919

(a)+(b)+(c) Cost of Capital Rate = 0.1534108

		(PTF)	
INVESTMENT BASE	$	5,142,947	From Worksheet 1
x Cost of Capital Rate		0.1534108	
= Investment Return and Income Taxes		788,984	To Worksheet 1

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2009
POST-1996

Shading denotes an input

	CAPITALIZATION 12/31/2009	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 160,909,090	35.26%	7.24%	2.55%	
PREFERRED STOCK	421,800	0.09%	7.00%	0.01%	0.01%
COMMON EQUITY	295,013,249	64.65%	11.64%	7.53%	7.53%
TOTAL INVESTMENT RETURN	$ 456,344,139	100.00%		10.09%	7.54%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.1009

(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)

= (0.0754 +((15,071) + 118,997) / 133,073,377) x 0.35) / (1 - 0.35)

= 0.0410205

(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)

= (0.0754 +((15,071) + 118,997) / 133,073,377) + 0.0410205)* 0.0893 / (1 - 0.0893)

= 0.0114924

(a)+(b)+(c) Cost of Capital Rate = 0.1534129

	(PTF)	
INVESTMENT BASE	$ 133,073,377	From Worksheet 1
x Cost of Capital Rate	0.1534129	
= Investment Return and Income Taxes	20,415,173	To Worksheet 1

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2009
POST-2003 (NRI)

Shading denotes an input

	CAPITALIZATION 12/31/2009	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 160,909,090	35.26%	0.00%	0.00%	
PREFERRED STOCK	421,800	0.09%	0.00%	0.00%	0.00%
COMMON EQUITY	295,013,249	64.65%	1.0%	0.65%	0.65%
TOTAL INVESTMENT RETURN	$ 456,344,139	100.00%		0.65%	0.65%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0065

(b) Federal Income Tax = $\dfrac{(\text{R.O.E.} \times \text{Federal Income Tax Rate})}{(1 - \text{Federal Income Tax Rate})}$

= $\dfrac{(0.0065 \times 0.35)}{(1 - 0.35)}$

= 0.0035000

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

= $\dfrac{(0.0065 + 0.0035000)}{(1 - 0.0893)} * 0.0893$

= 0.0009806

(a)+(b)+(c) Cost of Capital Rate = 0.0109806

	(PTF)	
INVESTMENT BASE (NRI)	$ 130,342,933	From Worksheet 1
x Cost of Capital Rate	0.0109806	
= Investment Return and Income Taxes	1,431,244	To Worksheet 1

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2009
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					6,437,698	Line 1, Worksheet 5
2	General Plant	39,796,843	12.2480% (a)	4,874,317	2.3368%	113,903	Page 207.96g
3	Total (line 1+2)			4,874,317		6,551,601	
4	Transmission Plant Held for Future Use	0		0	2.3368%	0	Page 214
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	(29,674,816)		(29,674,816)	2.3368%	(693,441)	Page 219.25b
6	General Plant Accum.Depreciation	(20,026,429)	12.2480% (a)	(2,452,837)	2.3368%	(57,318)	Page 219.28b
7	Total (line 5+6)			(32,127,653)		(750,759)	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)			(27,898,369) (d)	2.3368%	(651,929)	Page 450.1 Footnote
9	Accumulated Deferred Taxes (190)			1,327,230 (e)	2.3368%	31,015	Page 234 Footnote
10	Total (line 8+9)			(26,571,139)		(620,914)	
11	Transmission loss on Reacquired Debt	0	46.8962% (c)	0	2.3368%	0	Page 111.81c
	Other Regulatory Assets						
12	FAS 106	(30,108,780)	12.2480% (a)	(3,687,723)	2.3368%	(86,175)	Page 232.23f - Page 278.1f + part of Page 122a (Column C)
13	FAS 109	0	(f)	0	2.3368%	0	Excluded in Lines 8 & 9
14	Other Regulatory Liabilities (254.DK)	0	46.8962% (c)	0	2.3368%	0	n/a
15	Total (line 12+13+14)	(30,108,780)		(3,687,723)		(86,175)	
16	Transmission Prepayments	5,629,571	12.2480% (a)	689,510	2.3368%	16,112	Page 111.57c
17	Transmission Materials and Supplies	58,807		58,807	2.3368%	1,374	Page 227.8c
18	Cash Working Capital			1,374			
19	Operation & Maintenance Expense					52,053	Worksheet 1, Line 20
20	Administrative & General Expense					41,717	Worksheet 1, Line 21
21	Transmission Support Expense					159,894	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					253,664	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					31,708	

(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 2009
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		167,224,644	Line 1, Worksheet 5
2	General Plant	**39,796,843**	12.2480% (a)	4,874,317	60.7001%	2,958,715	Page 207.96g
3	Total (line 1+2)			4,874,317		170,183,359	
4	Transmission Plant Held for Future Use	0		0	60.7001%	0	Page 214
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	(29,674,816)		(29,674,816)	60.7001%	(18,012,643)	Page 219.25b
6	General Plant Accum.Depreciation	(20,026,429)	12.2480% (a)	(2,452,837)	60.7001%	(1,488,875)	Page 219.28b
7	Total (line 5+6)			(32,127,653)		(19,501,518)	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)			(27,898,369) (d)	60.7001%	(16,934,338)	Page 450.1
9	Accumulated Deferred Taxes (190)			1,327,230 (e)	60.7001%	805,630	Page 234 Footnote
10	Total (line 8+9)			(26,571,139)		(16,128,708)	
11	Transmission loss on Reacquired Debt	0	46.8962% (c)	0	60.7001%	0	Page 111.81c
	Other Regulatory Assets						
12	FAS 106	(30,108,780)	12.2480% (a)	(3,687,723)	60.7001%	(2,238,452)	Page 232.23f - Page 278.1f + part of Page 122a (Column C)
13	FAS 109	0	46.8962% (c)	0	60.7001%	0	Excluded in Lines 8 & 9
14	Other Regulatory Liabilities (254.DK)	0	46.8962% (c)	0	60.7001%	0	n/a
15	Total (line 12+13+14)	(30,108,780)		(3,687,723)		(2,238,452)	
16	Transmission Prepayments	5,629,571	12.2480% (a)	689,510	60.7001%	418,533	Page 111.57c
17	Transmission Materials and Supplies	58,807		58,807	60.7001%	35,696	Page 227.8c
18	Cash Working Capital						
19	Operation & Maintenance Expense					1,352,107	Worksheet 1, Line 20
20	Administrative & General Expense					1,083,627	Worksheet 1, Line 21
21	Transmission Support Expense					0	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					2,435,734	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					304,467	

(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 2009
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	5,460,647		5,460,647	2.3368%	127,604	Page 336.7b
2	General Depreciation	2,094,180	12.2480% (a)	256,495	2.3368%	5,994	Page 336.10b
3	Total (line 1+2)			5,717,142		133,598	
4	Amortization of Loss on Reacquired Debt	0	46.8962% (c)	0	2.3368%	0	Page 117.64c
5	Amortization of Investment Tax Credits	52,945	46.8962% (c)	24,829	2.3368%	580	Page 266.8f
	Property Taxes						
6	*Transmission Property Taxes*	5,422,933	46.8962% (c)	2,543,150	2.3368%	59,428	Page 262-263
8	Line 6			2,543,150		59,428	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	(9,527,612)		(9,527,612)	2.3368%	(222,641)	Page 321.112b
10	Transmission of Electricity by Others - #565	(12,476,465)		(12,476,465)	2.3368%	(291,550)	Page 321.96b
11	Load Dispatching - #561 - 561.4	721,334		721,334	2.3368%	16,856	Page 321.84b-88b
12	**Station Expenses & Rents - #562 / #567					0	Page 321.93b & .98b
13	O&M less lines 10, 11 & 12	2,227,519		2,227,519	2.3368%	52,053	
	Transmission Administrative and General						
14	Administrative and General	10,991,039					Page 323.197b
15	*less Property Insurance (#924)*	*260,394*					*Page 323.185b*
16	*less Regulatory Commission Expenses (#928)*	*1,613,582*					*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)]	9,117,063	12.2480% (a)	1,116,658	2.3368%	26,094	
19	*PLUS Property Insurance alloc. using Plant Allocation*	*260,394*	46.8962% *(c)*	122,115	2.3368%	2,854	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	*1,165,211*	46.8962% *(c)*	546,440	2.3368%	12,769	Exhibit: Reg Comission Expenses
21	*PLUS Trans. Related General Advertising Expense*	*0*	46.8962% *(c)*	0	2.3368%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*10,542,668*		*1,785,213*		*41,717*	
23	*Payroll Tax Expense*	*880,258*	12.2480% *(a)*	*107,814*	2.3368%	*2,519*	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	6,224	
FICA	865,138	
Medicare	0	
State Unemployment	8,896	
Total	880,258	*To Line 23*

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

Appropriate Property Taxes		
BHE 2009	3,349,858	
BHE 2008	2,073,075	
Total	5,422,933	*To Line 6*

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2009
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	5,460,647		5,460,647	60.7001%	3,314,618	Page 336.7b
2	General Depreciation	2,094,180	12.2480% (a)	256,495	60.7001%	155,693	Page 336.10b
3	Total (line 1+2)			5,717,142		3,470,311	
4	Amortization of Loss on Reacquired Debt	0	46.8962% (c)	0	60.7001%	0	Page 117.64c
5	Amortization of Investment Tax Credits	52,945	46.8962% (c)	24,829	60.7001%	15,071	Page 266.8f
	Property Taxes						
6	*Transmission Property Taxes*	5,422,933	46.8962% (c)	2,543,150	60.7001%	1,543,695	Page 262-263 FN.1-2
8	Line 6			2,543,150		1,543,695	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	(9,527,612)		(9,527,612)	60.7001%	(5,783,270)	Page 321.112b
10	Transmission of Electricity by Others - #565	(12,476,465)		(12,476,465)	60.7001%	(7,573,227)	Page 321.96b
11	Load Dispatching - #561	721,334		721,334	60.7001%	437,850	Page 321.84b-88b
12	**Station Expenses & Rents - #562 / #567					0	Page 321.93b & .98b
13	O&M less lines 10, 11 & 12	2,227,519		2,227,519	60.7001%	1,352,107	
	Transmission Administrative and General						
14	Administrative and General	10,991,039					Page 323.197b
15	*less Property Insurance (#924)*	260,394					*Page 323.185b*
16	*less Regulatory Commission Expenses (#928)*	1,613,582					*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)]	9,117,063	12.2480% (a)	1,116,658	60.7001%	677,813	
19	*PLUS Property Insurance alloc. using Plant Allocatior*	*260,394*	46.8962% *(c)*	122,115	60.7001%	74,124	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	1,165,211	46.8962% *(c)*	546,440	60.7001%	331,690	Exhibit: Reg Comission Expenses
21	*PLUS Trans. Related General Advertising Expense*	0	46.8962% *(c)*	0	60.7001%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*10,542,668*		*1,785,213*		*1,083,627*	
23	*Payroll Tax Expense*	*880,258*	12.2480% *(a)*	*107,814*	60.7001%	*65,443*	Footnote (d)

Notes: 65443.20581

(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	6,224	
FICA	865,138	
Medicare	0	
State Unemployment	8,896	
Total	880,258	*To Line 23*

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

Appropriate Property Taxes

BHE 2009	3,349,858	
BHE 2008	**2,073,075**	
Total	5,422,933	*To Line 6*

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2009
PRE-1997

Shading denotes an input

Line No.		Total	FERC Form 1 Reference
	PTF Transmission Plant Allocation Factor		
1	PTF Transmission Investment	6,437,698	ISO Catalog
2	Total Transmission Investment	275,493,092	Page 207.58g
3	Percent Allocation (Line 1/Line 2)	2.3368%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	1,232,194	Page 354.21b
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	1,232,194	
7	Total Wages and Salaries	12,657,353	Page 354.28b
8	Administrative and General Wages and Salaries	2,597,007	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)	10,060,346	
11	Percent Allocation (Line 6/Line 10)	12.2480%	
	Plant Allocation Factor		
12	Total Transmission Investment	275,493,092	Page 207.58g
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	4,874,317	*Worksheet 3, Line 2*
14	*= Revised Numerator (Line 12 + Line 13)*	280,367,409	
15	Total Plant in Service	597,846,508	Page 207.104g
16	Percent Allocation (Line 14 / Line 15)	46.8962%	

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2009
POST-1996

Shading denotes an input

Line No.		Total	FERC Form 1 Reference
	PTF Transmission Plant Allocation Factor		
1	PTF Transmission Investment	167,224,644	ISO Catalog
2	Total Transmission Investment	275,493,092	Page 207.58g
3	Percent Allocation (Line 1/Line 2)	60.7001%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	1,232,194	Page 354.21b
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	1,232,194	
7	Total Wages and Salaries	12,657,353	Page 354.28b
8	Administrative and General Wages and Salaries	2,597,007	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)	10,060,346	
11	Percent Allocation (Line 6/Line 10)	12.2480%	
	Plant Allocation Factor		
12	Total Transmission Investment	275,493,092	Page 207.58g
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	4,874,317	*Worksheet 3, Line 2*
14	*= Revised Numerator (Line 12 + Line 13)*	280,367,409	
15	Total Plant in Service	597,846,508	Page 207.104g
16	Percent Allocation (Line 14 / Line 15)	46.8962%	

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2009
Affiliated Company Wages and Salaries

Shading denotes an input

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

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2009

Shading denotes an input

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

Participant	PTF Supporting Facilities	FERC Form 1	Total Revenues (a)	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]		7,755
	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**			46,563
	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]		105,576
	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	159,894

Amount by which Support Expense exceeds Support Revenues: 159,894
(To Worksheet 3, Line 21, Column 5)

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2009
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	06/09-05/10	Appendix C	$1,148,916	$26,704,131	Sub-Total ATRR plus FTRR (excludes ATU)
2	Prior Year (Actual) Revenue Requirement	TY 2009		$1,198,243	$28,323,843	"Summary", line 29 (before FTRR & ATU)
3	Under / (Over) Forecast (Lines 2 - 1)			$49,327	$1,619,713	
4	Annual True Up (ATU)	06/09-05/10		$49,327	$1,619,713	

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2009
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	$33,000,000	
2	Carrying Charge Factor		Appendix C	17.55%	
3	Total Forecasted Revenue Requirements (Lines 1*2)			$5,791,225	

Line No.	II. CARRYING CHARGE FACTOR			
4	Investment Return and Income Taxes	(A)	$21,846,417	Worksheet 1 Post-96, line 14
5	Depreciation Expense	(B)	$3,470,311	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)	($15,071)	Worksheet 1 Post-96, line 17
8	Property Tax Expense	(E)	$1,543,695	Worksheet 1 Post-96, line 18
9	Payroll Tax Expense	(F)	$65,443	Worksheet 1 Post-96, line 19
10	Operation & Maintenance Expense	(G)	$1,352,107	Worksheet 1 Post-96, line 20
11	Administrative & General Expense	(H)	$1,083,627	Worksheet 1 Post-96, line 21
12	Total Expenses (Lines 4 thru 11)		$29,346,529	
13	PTF Transmission Plant	(A)(1)(a)	$167,224,644	Worksheet 1 Post-96, line 1
14	Carrying Charge Factor (Lines 12/13)		17.55%	

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2009
SUMMARY

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	Pre-97 Total	Post-96 Total	Reference
1	Transmission Plant	(A)(1)(a)	6,437,698	167,224,644	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	113,903	2,958,715	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)		6,551,601	170,183,359	
5	Accumulated Depreciation	(A)(1)(d)	(750,759)	(19,501,518)	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	(620,914)	(16,128,708)	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)	(86,175)	(2,238,452)	Worksheet 3, line 15 column 5
9	Net Investment (Line 4+5+6+7+8)		5,093,753	132,314,681	
10	Prepayments	(A)(1)(h)	16,112	418,533	Worksheet 3, line 16 column 5
11	Materials & Supplies	(A)(1)(i)	1,374	35,696	Worksheet 3, line 17 column 5
12	Cash Working Capital	(A)(1)(j)	31,708	304,467	Worksheet 3, line 24 column 5
13	Total Investment Base (Line 9+10+11+12)		5,142,947	133,073,377	

	II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	788,984	21,846,417	Worksheet 2
15	Depreciation Expense	(B)	133,598	3,470,311	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)	(580)	(15,071)	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	59,428	1,543,695	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	2,519	65,443	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	(G)	52,053	1,352,107	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	41,717	1,083,627	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)	159,894	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)	(32,529)	(844,956)	Worksheet 1, line 27
28	Transmission Rents Received from Electric Property	(O)	(6,842)	(177,730)	Worksheet 1, line 28
29	Total Revenue Requirements (Line 14 thru 28)		1,198,243	28,323,843	

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements of PTF Facilities
For Costs In 2009
INTEREST

Shading denotes an input

Pre 97 Under / (Over)	Post-96 Under/ (Over)
$49,327	$1,619,713

Initial Billing Period	Pre-97 Balance	Psot-96 Balance	FERC Monthly Interest Rate	Pre-97 Interest	Post-96 Interest
June-09	$ 49,327	$ 1,619,713	0.28%	$ 138	$ 4,535
July-09	$ 49,465	$ 1,624,248	0.28%	$ 139	$ 4,548
August-09	$ 49,465	$ 1,624,248	0.28%	$ 139	$ 4,548
September-09	$ 49,465	$ 1,624,248	0.27%	$ 134	$ 4,385
October-09	$ 49,876	$ 1,637,729	0.28%	$ 140	$ 4,586
November-09	$ 49,876	$ 1,637,729	0.27%	$ 135	$ 4,422
December-09	$ 49,876	$ 1,637,729	0.28%	$ 140	$ 4,586
January-10	$ 50,290	$ 1,651,322	0.28%	$ 141	$ 4,624
February-10	$ 50,290	$ 1,651,322	0.25%	$ 126	$ 4,128
March-10	$ 50,290	$ 1,651,322	0.28%	$ 141	$ 4,624
April-10	$ 50,697	$ 1,664,698	0.27%	$ 137	$ 4,495
May-10	$ 50,697	$ 1,664,698	0.28%	$ 142	$ 4,661
			Total Interest	$ 1,649	$ 54,141
			True-Up	$49,327	$1,619,713
			Total TU & Int	$ 50,976	$ 1,673,854

Exhibit: Regulatory Commission Expenses

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Regulatory Commission Expenses for 2009
Reconciliation of FERC Form 1 Data to Exhibit 5

Line	a Description		b Expenses Booked		c Reference
1	Expenses booked to Account 923 (directly related to reg proceedings)	$	5,062		Exhibit: Outside Legal Expenses (#923), line 13c
2	Regulatory commission expenses booked to Account 928	$	1,613,582		FF1 pg 350.46d
3	Line 2, directly attributable to Transmission				
a	Annual Federal Regulatory Assessment	$	159,959		
b	Order 890 Compliance	$	698		
c	2009 Transmission Rate Case	$	141,451		
d	General Transmission	$	53,134		
e	ROE ER04-157	$	2,672		
f	ISO-Withdrawal 2008-256	$	193,854		
g	CMP MPRP 2008-255	$	3,293		
h	First Wind Energy	$	20,606		
i	UPC Wind	$	11,476		
4	Account 928 directly related to Transmission	$	587,143		
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)	$	285,228		Notes, Line 14c
7	6 months of 2009 pro-forma ommission of RTO Amortization costs	$	287,778		Notes, Line 13c / 2
8	Total	$	1,165,211		Line 1+4+5+6+7
9					
10	a		b		c
11	Notes				
12	1) 2008	$	582,698		
13	2) 2009	$	570,456	$	575,557
14	3) 2010	$	47,538	$	285,228

Exhibit: Transmission Rents

Bangor Hydro-Electric Company (BHE)
Annual Revenue Requirements for Transmission Facilities
Transmission Rents for 2009

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

Braintree Electric Light Department

Sheet: Input Panel | Input Panel

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

Shading denotes an input

Submitted on:	05/21/2009
Revenue Requirements for (year):	2009
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	=	162,824	(a)	1,928,494	(f)
Total of Attachment F - Section J - Support Revenue		0	(b)	0	(g)
Total of Attachment F - Section K - Support Expense		74,076	(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)		236,900	(e)=(a)-(b)+(c)+(d)	1,928,494	(j)=(f)-(g)+(h)+(i)
Forecasted Incremental Transmission Revenue Requirements				0	(m)
Annual True-up		(40,249)		550,033	(n)
Interest Charge on Annual True-up		(1,977)	(l)	27,012	(o)
Total = (e) + (j) + (k) + (l) + (m) + (n) + (o)		194,674	(p)	2,505,539	(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:				2,700,213	(r) = (p)+(q)

RNS Rate

Braintree Electric Light Department
Annual Revenue Requirements of pre-1997 & post-1996 PTF
for costs in 2008 06/09-05/10

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	Pre 1997	Post 1996	Reference
1	Transmission Plant	I (A)(1)(a)	1,758,281	14,285,577	Worksheet 3, line 1 column 5
2	General Plant	I (A)(1)(b)	4,980	40,458	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)		1,763,261	14,326,035	
5	Accumulated Depreciation	I (A)(1)(d)	948,250	7,704,285	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)		815,011	6,621,750	
10	Prepayments	I (A)(1)(h)	23	183	Worksheet 3, line 16 column 5
11	Materials & Supplies	I (A)(1)(i)	315	2,556	Worksheet 3, line 17 column 5
12	Cash Working Capital	I (A)(1)(j)	17,184	31,535	Worksheet 3, line 24 column 5
13	Total Investment Base (Line 9+11+12+13)		832,533	6,656,024	
	II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	I (A)	66,603	532,482	Worksheet 2
15	Depreciation Expense	I (B)	49,725	404,007	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)	22,790	185,161	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	I (F)	557	4,524	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	I (G)	18,880	153,396	Worksheet 4, line 13 column 5
21	Administrative & General Expense	I (H)	12,171	98,891	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)	106,423	0	Worksheet 7
25	Transmission Related Expense from Generators	I (L)	0	0	
26	Transmission Related Taxes and Fees Charge	I (M)	0	0	
27	Revenue for ST Trans. Service Under NEPOOL 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)		277,149	1,378,461	

III. CURRENT CALENDAR YEAR ESTIMATED INCREMENTAL REVENUE REQUIREMENT

Line No.		
30	Carrying Charge Factor Base Revenue Requirement Numerator	1,549,187
31	Post-2003 Enhanced Return Addition to Revenue Requirement	-
32	Total Post-96 PTF Revenue Requirement	1,549,187
33	Post-96 PTF Transmission Plant in Service	14,285,577
34	Post-96 Carrying Charge Factor (Post-96 CCF)	9.6%
35	Forecasted Post-96 PTF Plant Additions	0
36	Forecasted Post-96 Localized PTF Plant Additions	0
37	Forecasted Post-96 Pool-Supported PTF Plant Additions	0
38	Post-96 Estimated Incremental Revenue Requirement	0

RNS Rate

Braintree Electric Light Department
FERC Interest Calculation associated with Under / (Over)
True Up and Interest Calculation for 2009

1	2008 Actual Annual RR			236,900	1,928,494	Input Panel Subtotals
2	2008 Est. Transmission Revenue Requirements (as billed)	6/00-05/10	Appendix C	277,149	1,378,461	ATRR - Prior Year
3	True-up (Over)/Under (Line 1 - Line 2)			-40,249	550,033	

	Overcollection/(Undercollection)
Pre'97	($40,249)
Post'96	$550,033

Initial Billing Period	Pre 1997 Balance	Post 1996 Balance	FERC Monthly Interest Rate	Pre 1997 Interest	Post 1996 Interest
June 2007	($40,249)	$550,033	0.56%	($225)	$3,080
July 2007	(40,474)	553,113	0.45%	-182	$2,489
August 2007	(40,474)	553,113	0.45%	-182	$2,489
September 2007	(40,474)	553,113	0.44%	-178	$2,434
October 2007	(41,017)	560,525	0.42%	-172	$2,354
November 2007	(41,017)	560,525	0.41%	-168	$2,298
December 2007	(41,017)	560,525	0.42%	-172	$2,354
January 2008	(41,529)	567,531	0.38%	-158	$2,157
February 2008	(41,529)	567,531	0.34%	-141	$1,930
March 2008	(41,529)	567,531	0.38%	-158	$2,157
April 2008	(41,986)	573,774	0.28%	-118	$1,607
May 2008	(41,986)	573,774	0.29%	-122	$1,664
		Total Interest		-$1,977	$27,012
		True-Up		-$40,249	$550,033
		Total TU & Int		**-$42,226**	**$577,045**

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:	21-May-09
Revenue Requirements for (year):	Calendar Year 2009
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	=	162,824	(a)		(f)
Total of Attachment F - Section J - Support Revenue		0	(b)	0	(g)
Total of Attachment F - Section K - Support Expense		74,076	(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)		236,900	(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:	236,900	(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)	236,900	(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)	10,948	Worksheet 3a, L11
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3a, L14
4	Total Plant (Lines 1+2+3)		1,714,851	
5	Accumulated Depreciation	(A)(1)(d)	722,546	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)		992,305	
10	Prepayments	(A)(1)(h)	73	Worksheet 3a, L34
11	Materials & Supplies	(A)(1)(i)	2,793	Worksheet 3a, L36
12	Cash Working Capital	(A)(1)(j)	11,938	Worksheet 3a, 44
13	Total Investment Base (Line 9+10+11+12)		1,007,109	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	80,569	Worksheet 2a, E56
15	Depreciation Expense	(B)	43,994	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)	15,671	Worksheet 4a, L21
19	Payroll Tax Expense	(F)	1,166	Worksheet 4a, L42
20	Operation & Maintenance Expense	(G)	10,661	Worksheet 4a, L29
21	Administrative & General Expense	(H)	10,763	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)	74,076	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)		236,900	
			162,824	

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

(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) / 1,007,109) 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) / 1,007,109) + 0.0000000)* 0 / (1 - 0)

= 0.0000000

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

		(PTF)	
INVESTMENT BASE	$	1,007,109	From Worksheet 1
x Cost of Capital Rate		0.0800000	
= Investment Return and Income Taxes		80,569	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	$ 22,740,899		22,740,899		1,703,903	Worksheet 5, E12
2	General Plant	$ 15,414,816	0.9479% (a)	146,117	7.4927%	10,948	Page 8B line 29(g)
3	Total (line 1+2)			22,887,016		1,714,851	
4	Transmission Plant Held for Future Use	0		0	7.4927%	0	None known
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	9,597,083		9,597,083	7.4927%	719,081	Page 8A, line 31(g) less Page 16, line 31(g)
6	General Plant Accum.Depreciation	4,878,337	0.9479% (a)	46,242	7.4927%	3,465	Page 8B, line 29(g) less Page 17, line 29(g)
7	Total (line 5+6)			9,643,325		722,546	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	0	10.8004% (c)	0	7.4927%	0	None known
9	Accumulated Deferred Taxes (190)	0	10.8004% (c)	0	7.4927%	0	None known
10	Total (line 8+9)			0		0	
11	Transmission loss on Reacquired Debt	0	10.8004% (c)	0	7.4927%	0	None known
	Other Regulatory Assets						
12	FAS 106	0	0.9479% (a)	0	7.4927%	0	None known
13	FAS 109	0	10.8004% (c)	0	7.4927%	0	None known
14	Other Regulatory Liabilities (254.DK)	0	10.8004% (c)	0	7.4927%	0	
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments	102,649	0.9479% (a)	973	7.4927%	73	Page 10, Line 26 MA DTE
17	Transmission Materials and Supplies	3,932,409	0.9479%	37,275	7.4927%	2,793	Page 10, Line 24 MA DTE
18	Cash Working Capital						
19	Operation & Maintenance Expense					10,661	Worksheet 1, Line 20
20	Administrative & General Expense					10,763	Worksheet 1, Line 21
21	Transmission Support Expense					74,076	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					95,500	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					11,938	

(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	582,987		582,987	7.4927%	43,681	Page 16, line 31(d)
2	General Depreciation	440,811	0.9479% (a)	4,178	7.4927%	313	Page 17, line 29(d)
3	Total (line 1+2)			587,165		43,994	
4	Amortization of Loss on Reacquired Debt	0	10.8004% (c)	0	7.4927%	0	None known
5	Amortization of Investment Tax Credits	0	10.8004% (c)	0	7.4927%	0	None known
	Property Taxes *						
6	Transmission Property Taxes	1,780,373	0.108004	192,287	7.4927%	14,407	Page 21, line 33 (b)
7	General Property Taxes	1,780,373	0.9479% (a)	16,876	7.4927%	1,264	Page 21, line 33 (b)
8	Total (line 6+7)			209,163		15,671	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	148,207		148,207	0.074927	11,105	Page 40, line 50(b)
10	Transmission of Electricity by Others - #565	0		0	0.074927	0	Page 40, line 38(b)
11	Load Dispatching - #561	0		0	0.074927	0	Page 40, line 34(b)
12	**Station Expenses & Rents - #562 / #567	5,920		5,920	0.074927	444	Page 40, line 35(b) 40(b)
13	O&M less lines 10, 11 & 12	142,287		148,207	7.4927%	10,661	
	Transmission Administrative and General						
14	Administrative and General	8,076,639					Page 42, line 5(b)
15	*less Property Insurance (#924)*	*683,320*					Page 41, line 47(b)
16	*less Regulatory Commission Expenses (#928)*	0					Page 41, line 50(b)
17	*less General Advertising Expense (#930.1)*	*25,519*					*assumed none*
18	Subtotal [line 14 minus (15 thru 17)]	7,367,800	0.9479% (a)	69,839	7.4927%	5,233	
19	*PLUS Property Insurance alloc. using Plant Allocatior*	*683,320*	*10.8004% (c)*	73,801	7.4927%	5,530	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	*0*	*10.8004% (c)*	0	7.4927%	0	
21	*PLUS Trans. Related General Advertising Expense*	*0*	*10.8004% (c)*	0	7.4927%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*8,051,120*		*143,640*		*10,763*	
23	*Payroll Tax Expense*	1,642,035	*0.9479% (a)*	*15,565*	*7.4927%*	*1,166*	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.		Braintree	Mass DTE AR Reference
	PTF Transmission Plant Allocation Factor		
1	PTF Transmission Investment	1,703,903	Per Braintree Workpapers
2	Total Transmission Investment	22,740,899	Page 8A, line 31(g)
3	Percent Allocation (Line 1/Line 2)	7.4927%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	82,000	See BELD General Ledger
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 of 7
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	82,000	
7	Total Wages and Salaries	9,154,204	Page 42, line 24 (c)
8	Administrative and General Wages and Salaries	503,174	Page 41, line 43(b)
9	Affiliated Company Wages and Salaries less A&G	0	Worksheet 6
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	8,651,030	
11	Percent Allocation (Line 6/Line 10)	0.9479%	
	Plant Allocation Factor		
12	Total Transmission Investment	22,740,899	Line 2
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	146,117	*Worksheet 3, Line 2*
14	*= Revised Numerator (Line 12 + Line 13)*	22,887,016	
15	Total Plant in Service	211,908,988	Page 8B, line 30 (g)
16	Percent Allocation (Line 14 / Line 15)	10.8004%	

Sheet: Worksheet 6

Affiliated Company Wages and Salaries

Shading denotes an input

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

Sheet: Worksheet 7

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

Participant	PTF Supporting Facilities	FERC Form 1	TOTAL Revenues (a)	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]		$1,348
	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**			$9,607
	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			
NEP	**Moore 115 kV Substation**	332.1(g)		
	HQ Phase II - AC in MA	332.1(g); [332(g) for CL&P]		$20,729
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 394 line	332(g)		$2,596
	115 kV Read - Washington V148 line			
NU	**345 kV 363, 369 and 394 Seabrook lines**			$2,215
	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				$37,581
		Total =	0	74,076

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:	21-May-10
Revenue Requirements for (year):	Calendar Year 2009
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)	1,928,494	(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)	1,928,494	(j)

Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:	1,928,494	(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)	1,928,494	(l)=(k)+(b)+(g)-(h)

Calendar Year 2009

Shading denotes an input

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	Braintree	Reference
1	Transmission Plant	(A)(1)(a)	20,283,972	Worksheet 3a, L10
2	General Plant	(A)(1)(b)	130,331	Worksheet 3a, L11
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3a, L14
4	Total Plant (Lines 1+2+3)		20,414,303	
5	Accumulated Depreciation	(A)(1)(d)	8,601,460	Worksheet 3a, L19
6	Accumulated Deferred Income Taxes	(A)(1)(e)	0	Worksheet 3a, L24
7	Loss On Reacquired Debt	(A)(1)(f)	0	Worksheet 3a, L26
8	Other Regulatory Assets	(A)(1)(g)	0	Worksheet 3a, L32
9	Net Investment (Line 4-5-6+7+8)		11,812,843	
10	Prepayments	(A)(1)(h)	868	Worksheet 3a, L34
11	Materials & Supplies	(A)(1)(i)	33,248	Worksheet 3a, L36
12	Cash Working Capital	(A)(1)(j)	31,844	Worksheet 3a, 44
13	Total Investment Base (Line 9+10+11+12)		11,878,803	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	950,304	Worksheet 2a, E56
15	Depreciation Expense	(B)	523,728	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)	185,826	Worksheet 4a, L21
19	Payroll Tax Expense	(F)	13,883	Worksheet 4a, L42
20	Operation & Maintenance Expense	(G)	126,915	Worksheet 4a, L29
21	Administrative & General Expense	(H)	127,838	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)		1,928,494	

Braintree Electric Light Department
Annual Revenue Requirements - 2007
Calendar Year 2009

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 = (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) / 11,878,803) 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) / 11,878,803) + 0.0000000)* 0 / (1 - 0)

= 0.0000000

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

	(PTF)	
INVESTMENT BASE	$ 11,878,803	From Worksheet 1
x Cost of Capital Rate	0.0800000	
= Investment Return and Income Taxes	950,304	To Worksheet 1

Braintree Electric Light Department

Calendar Year 2009

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	$ 22,740,899		22,740,899		20,283,972	Worksheet 5, E12
2	General Plant	$ 15,414,816	0.9479% (a)	146,117	89.1960%	130,331	Page 8B line 29(g)
3	Total (line 1+2)			22,887,016		20,414,303	
4	Transmission Plant Held for Future Use	0		0	89.1960%	0	None known
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	9,597,083		9,597,083	89.1960%	8,560,214	Page 8A, line 31(g) less Page 16, line 31(g)
6	General Plant Accum.Depreciation	4,878,337	0.9479% (a)	46,242	89.1960%	41,246	Page 8B, line 29(g) less Page 17, line 29(g)
7	Total (line 5+6)			9,643,325		8,601,460	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	0	10.7538% (c)	0	89.1960%	0	None known
9	Accumulated Deferred Taxes (190)	0	10.7538% (c)	0	89.1960%	0	None known
10	Total (line 8+9)			0		0	
11	Transmission loss on Reacquired Debt	0	10.7538% (c)	0	89.1960%	0	None known
	Other Regulatory Assets						
12	FAS 106	0	0.9479% (a)	0	89.1960%	0	None known
13	FAS 109	0	10.7538% (c)	0	89.1960%	0	None known
14	Other Regulatory Liabilities (254.DK)	0	10.7538% (c)	0	89.1960%	0	
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments	102,649	0.9479% (a)	973	89.1960%	868	Page 10, Line 26 MA DTE
17	Transmission Materials and Supplies	3,932,409	0.9479%	37,275	89.1960%	33,248	Page 10, Line 24 MA DTE
18	Cash Working Capital						
19	Operation & Maintenance Expense					126,915	Worksheet 1, Line 20
20	Administrative & General Expense					127,838	Worksheet 1, Line 21
21	Transmission Support Expense					0	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					254,753	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					31,844	

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

Braintree Electric Light Department

Calendar Year 2009

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	582,987		582,987	89.1960%	520,001	Page 16, line 31(d)
2	General Depreciation	440,811	0.9479% (a)	4,178	89.1960%	3,727	Page 17, line 29(d)
3	Total (line 1+2)			587,165		523,728	
4	Amortization of Loss on Reacquired Debt	0	10.7538% (c)	0	89.1960%	0	None known
5	Amortization of Investment Tax Credits	0	10.7538% (c)	0	89.1960%	0	None known
	Property Taxes *						
6	Transmission Property Taxes	1,780,373	0.107538	191,458	89.1960%	170,773	Page 21, line 33 (b)
7	General Property Taxes	1,780,373	0.9479% (a)	16,876	89.1960%	15,053	Page 21, line 33 (b)
8	Total (line 6+7)			208,334		185,826	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	148,207		148,207	0.89196	132,195	Page 40, line 50(b)
10	Transmission of Electricity by Others - #565	0		0	0.89196	0	Page 40, line 38(b)
11	Load Dispatching - #561	0		0	0.89196	0	Page 40, line 34(b)
12	**Station Expenses & Rents - #562 / #567	5,920		5,920	0.89196	5,280	Page 40, line 35(b) 40(b)
13	O&M less lines 10, 11 & 12	142,287		148,207	89.1960%	126,915	
	Transmission Administrative and General						
14	Administrative and General	8,076,639					Page 42, line 5(b)
15	*less Property Insurance (#924)*	*683,320*					Page 41, line 47(b)
16	*less Regulatory Commission Expenses (#928)*	0					Page 41, line 50(b)
17	*less General Advertising Expense (#930.1)*	*25,519*					*assumed none*
18	Subtotal [line 14 minus (15 thru 17)]	7,367,800	0.9479% (a)	69,839	89.1960%	62,294	
19	*PLUS Property Insurance alloc. using Plant Allocatior*	*683,320*	*10.7538% (c)*	73,483	89.1960%	65,544	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	*0*	*10.7538% (c)*	0	89.1960%	0	
21	*PLUS Trans. Related General Advertising Expense*	*0*	*10.7538% (c)*	0	89.1960%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*8,051,120*		*143,322*		*127,838*	
23	*Payroll Tax Expense*	1,642,035	*0.9479% (a)*	*15,565*	*89.1960%*	*13,883*	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 2009

Line No.		Braintree	Mass DTE AR Reference
	PTF Transmission Plant Allocation Factor		
1	PTF Transmission Investment	20,283,972	Per Braintree Workpapers
2	Total Transmission Investment	22,740,899	Page 8A, line 31(g)
3	Percent Allocation (Line 1/Line 2)	89.1960%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	82,000	See BELD General Ledger
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 of 7
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	82,000	
7	Total Wages and Salaries	9,154,204	Page 42, line 24 (c)
8	Administrative and General Wages and Salaries	503,174	Page 41, line 43(b)
9	Affiliated Company Wages and Salaries less A&G	0	Worksheet 6
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	8,651,030	
11	Percent Allocation (Line 6/Line 10)	0.9479%	
	Plant Allocation Factor		
12	Total Transmission Investment	22,740,899	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)*	22,788,315	
15	Total Plant in Service	211,908,989	Page 8B, line 30 (g)
16	Percent Allocation (Line 14 / Line 15)	10.7538%	

Sheet: Worksheet 6

Affiliated Company Wages and Salaries

Shading denotes an input

Calendar Year 2009

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 2009

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 17, 2010	
Revenue Requirements for (test year):	Calendar Year 2009	
Rates Effective for the period:	June 1, 2010	
through:	May 31, 2011	
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	=	$ 19,209,954	(a)	$ 31,170,608	(f)
Total of Attachment F - Section J - Support Revenue		509,966	(b)	-	(g)
Total of Attachment F - Section K - Support Expense		691,822	(c)	-	(h)
Total of Attachment F - Section (L through O)		(597,326)	(d)	(941,286)	(i)
Sub Total - Sum (A through I) - J + K + (L through O)		18,794,484	(e)=(a)-(b)+(c)+(d)	30,229,322	(j)
Forecasted Transmission Revenue Requirements (per Appendix C to Attachment F Implementation Rule)		N/A		33,727,217	(k)
Annual True-up (per Appendix C to Attachment F Implementation Rule)		506,717	(l)	3,122,169	(m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)		**$ 19,301,201**	(n)=(e)+(l)	**$ 67,078,708**	(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)	**$ 86,379,909**	(p) = (n)+(o)

CMP
Annual Revenue Requirements of PTF Facilities
2009

Line No.			Attachment F Reference Section:	PRE97	POST 1996	TOTAL	Reference
	I.	INVESTMENT BASE					
1		Transmission Plant	(A)(1)(a)	$ 111,787,718	176,158,940	$ 287,946,658	Worksheet 3, line 1&2 c
2		General Plant	(A)(1)(b)	3,251,403	5,123,672	8,375,075	Worksheet 3, line 3 colu
3		Plant Held For Future Use	(A)(1)(c)	4,126,296	6,502,359	10,628,655	Worksheet 3, line 5 colu
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 3, line 8 colu
6		Accumulated Deferred Income Taxes	(A)(1)(e)	8,980,064	14,151,095	23,131,159	Worksheet 3, line 11 co
7		Loss On Reacquired Debt	(A)(1)(f)	310,657	489,544	800,201	Worksheet 3, line 12 co
8		Other Regulatory Assets	(A)(1)(g)	323,726	510,138	833,864	Worksheet 3, line 16 co
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 3, line 17 co
11		Materials & Supplies	(A)(1)(i)	687,588	1,083,525	1,771,113	Worksheet 3, line 18 co
12		Cash Working Capital	(A)(1)(j)	610,444	926,136	1,536,580	Worksheet 3, line 25 co
13		Total Investment Base (Line 9+10+11+12)		$ 70,988,955	$ 111,831,016	$ 182,819,971	
	II.	REVENUE REQUIREMENTS					
14		Investment Return and Income Taxes	(A)	$ 10,637,524	$ 17,661,877	$ 28,299,401	Worksheet 2
15		Depreciation Expense	(B)	2,861,211	4,508,795	7,370,006	Worksheet 4, line 3, col
16		Amortization of Loss on Reacquired Debt	(C)	49,468	77,953	127,421	Worksheet 4, line 4, col
17		Investment Tax Credit	(D)	(50,619)	(79,767)	(130,386)	Worksheet 4, line 5, col
18		Property Tax Expense	(E)	1,010,677	1,592,660	2,603,337	Worksheet 4, line 6, col
19		Payroll Tax Expense	(F)	-	-	-	Worksheet 4, line 22, co
20		Operation & Maintenance Expense	(G)	3,415,913	5,382,913	8,798,826	Worksheet 4, line 11, co
21		Administrative & General Expense	(H)	1,285,780	2,026,177	3,311,957	Worksheet 4, line 21, co
22		Transmission Related Integrated Facilities Charge	(I)	-	-	-	Attachment 4, line 6
23		Transmission Support Revenue	(J)	(509,966)	-	(509,966)	Worksheet 6
24		Transmission Support Expense	(K)	691,822	-	691,822	Worksheet 6
25		Transmission Related Expense from Generators	(L)	-	-	-	Worksheet 7
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)	Attachment 7
28		Transmission Rents Received from Electric Property	(O)	-	-	-	Attachment 6
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	

CMP
Annual Revenue Requirements of PTF Facilities
2008

Line No.			Attachment F Reference Section:	PRE 97	POST 1996	TOTAL	Ref
	I.	INVESTMENT BASE					
1		Transmission Plant	(A)(1)(a)	$ 112,568,567	$ 133,220,884	$ 245,789,452	Worksheet 1
2		General Plant	(A)(1)(b)	3,172,325	3,754,334	6,926,659	Worksheet 1
3		Plant Held For Future Use	(A)(1)(c)	458,808	542,983	1,001,791	Worksheet 1
4		Total Plant (Lines 1+2+3)		116,199,700	137,518,201	253,717,902	
5		Accumulated Depreciation	(A)(1)(d)	45,106,810	53,382,314	98,489,124	Worksheet 1
6		Accumulated Deferred Income Taxes	(A)(1)(e)	8,254,663	9,769,102	18,023,765	Worksheet 1
7		Loss On Reacquired Debt	(A)(1)(f)	381,923	451,993	833,916	Worksheet 1
8		Other Regulatory Assets	(A)(1)(g)	384,387	454,909	839,296	Worksheet 1
9		Net Investment (Line 4-5-6+7+8)		63,604,537	75,273,687	138,878,225	
10		Prepayments	(A)(1)(h)	124,181	146,964	271,145	Worksheet 1
11		Materials & Supplies	(A)(1)(i)	810,208	958,852	1,769,060	Worksheet 1
12		Cash Working Capital	(A)(1)(j)	649,698	752,310	1,402,008	Worksheet 1
13		Total Investment Base (Line 9+10+11+12)		$ 65,188,624	$ 77,131,813	$ 142,320,438	Worksheet 1
	II.	REVENUE REQUIREMENTS					
14		Investment Return and Income Taxes	(A)	$ 10,072,796	$ 12,675,091	$ 22,747,887	Worksheet 1
15		Depreciation Expense	(B)	2,755,519	3,261,060	6,016,579	Worksheet 1
16		Amortization of Loss on Reacquired Debt	(C)	55,030	65,126	120,156	Worksheet 1
17		Investment Tax Credit	(D)	(52,218)	(61,798)	(114,016)	Worksheet 1
18		Property Tax Expense	(E)	1,048,199	1,240,507	2,288,706	Worksheet 1
19		Payroll Tax Expense	(F)	-	-	-	
20		Operation & Maintenance Expense	(G)	3,472,976	4,110,144	7,583,120	Worksheet 1
21		Administrative & General Expense	(H)	1,612,501	1,908,337	3,520,838	Worksheet 1
22		Transmission Related Integrated Facilities Charge	(I)	-	-	-	Worksheet 1
23		Transmission Support Revenue	(J)	(596,141)	-	(596,141)	Worksheet 1
24		Transmission Support Expense	(K)	708,244	-	708,244	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)	(772,749)	(914,521)	(1,687,270)	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)		$ 18,304,157	$ 22,283,946	$ 40,588,103	
30		Forecasted PTF Revenue Requirements - 2008		-	4,924,194	4,924,194	
31		Total RNS Rev Req'ts subject to Annual True-up		$ 18,304,157	$ 27,208,140	$ 45,512,297	
32		PY true-up		371,270	809,740	1,181,010	
33		Total RNS-6/1/08-5/31/09		$ 18,675,428	$ 28,017,880	$ 46,693,308	

CMP
Transmission Revenue Requirements of PTF Facilities
2009 True-up

	I.	APPENDIX C - ANNUAL TRUE-UP	Rate Year	PRE97	POST 1996	Total	Reference
1		ATRR for True-up = 2009 Actual	6/1/10-5/31/2011	$ 18,794,484	$ 30,229,322	$ 49,023,806	Summary 6-1-10_5-31-11, line 29
2		ATRR subject to True-up = '08 TY + '09 Forecast (as billed)	6/1/09-5/31/2010	$ 18,304,157	$ 27,208,140	$ 45,512,297	Summary 6-1-09_5-31-10, line 29
3		Annual True-up (Line 1 - Line 2)		$ 490,327	$ 3,021,182	$ 3,511,509	

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

	Undercollection / (Overcollection)
PRE97	490,327
Post1996	3,021,182

Initial Billing Period	PRE97 Balance	POST 1996 Balance	FERC Monthly Interest Rate	PRE97 Interest	POST 1996 Interest	
June 2009	490,327	3,021,182	0.28%	$ 1,372.92	$ 8,459.31	
July 2009	491,700	3,029,641	0.28%	1,376.76	8,483.00	
August 2009	491,700	3,029,641	0.28%	1,376.76	8,483.00	
September 2009	491,700	3,029,641	0.27%	1,327.59	8,180.03	
October 2009	495,781	3,054,787	0.28%	1,388.19	8,553.40	
November 2009	495,781	3,054,787	0.27%	1,338.61	8,247.93	
December 2009	495,781	3,054,787	0.28%	1,388.19	8,553.40	
January 2010	499,896	3,080,142	0.28%	1,399.71	8,624.40	
February 2010	499,896	3,080,142	0.25%	1,249.74	7,700.36	
March 2010	499,896	3,080,142	0.28%	1,399.71	8,624.40	
April 2010	503,945	3,105,091	0.27%	1,360.65	8,383.75	
May 2010	503,945	3,105,091	0.28%	1,411.05	8,694.26	
		Total Interest		$ 16,390	$ 100,987	$ 117,377
		True-Up		490,327	3,021,182	3,511,509
		Total TU & Int		$ 506,717	$ 3,122,169	$ 3,628,886

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/09

Line No.			Attachment F Reference Section:		Reference
	II.	INVESTMENT BASE			
1		Transmission Plant	II (A)(1)(a)	$ 111,787,718	Worksheet 3, line 1 column 5
2		General Plant	II (A)(1)(b)	3,251,403	Worksheet 3, line 2 column 5
3		Plant Held For Future Use	II (A)(1)(c)	4,126,296	Worksheet 3, line 4 column 5
4		Total Plant (Lines 1+2+3)		119,165,417	
5		Accumulated Depreciation	II (A)(1)(d)	41,209,100	Worksheet 3, line 7 column 5
6		Accumulated Deferred Income Taxes	II (A)(1)(e)	8,980,064	Worksheet 3, line 10 column 5
7		Loss On Reacquired Debt	II (A)(1)(f)	310,657	Worksheet 3, line 11 column 5
8		Other Regulatory Asssets	II (A)(1)(g)	323,726	Worksheet 3, line 14 column 5
9		Net Investment (Line 4-5-6+7+8)		69,610,636	
10		Prepayments	II (A)(1)(h)	80,287	Worksheet 3, line 15 column 5
11		Materials & Supplies	II (A)(1)(i)	687,588	Worksheet 3, line 16 column 5
12		Cash Working Capital	II (A)(1)(j)	610,444	Worksheet 3, line 23 column 5
13		Total Investment Base (Line 9+10+11+12)		$ 70,988,955	
	II.	REVENUE REQUIREMENTS			
14		Investment Return and Income Taxes	II (A)	$ 10,637,524	Worksheet 2
15		Depreciation Expense	II (B)	2,861,211	Worksheet 4, line 3 column 5
16		Amortization of Loss on Reacquired Debt	II (C)	49,468	Worksheet 4, line 4 column 5
17		Investment Tax Credit	II (D)	(50,619)	Worksheet 4, line 5 column 5
18		Municipal Taxes	II (E)	1,010,677	Worksheet 4, line 8 column 5
19		Payroll Taxes	II (F)	-	Worksheet 4, line 9 column 5
20		Operation & Maintenance Expense	II (G)	3,415,913	Worksheet 4, line 14 column 5
21		Administrative & General Expense	II (H)	1,285,780	Worksheet 4, line 18 column 5
22		Transmission Related Integrated Facilities Charge	II (I)	-	
23		Transmission Support Revenue	II (J)	(509,966)	Worksheet 7, line 11 column a
24		Transmission Support Expense	II (K)	691,822	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)	(597,326)	Worksheet 20
28		Transmission Rents Received from Electric Property	II (O)	-	
29		Total Revenue Requirements (Line 14 thru 28)		$ 18,794,484	

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/09

see w/s 12 - capitalization		CAPITALIZATION	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	462,700,000	35.044%	6.648%	2.330%	
PREFERRED STOCK		13,571,300	1.028%	4.993%	0.051%	0.051%
COMMON EQUITY		844,058,753	63.928%	11.640%	7.441%	7.441%
TOTAL INVESTMENT RETURN	$	1,320,330,053	100.00%		9.822%	7.492%

Cost of Capital Rate=

(a) Weighted Cost of Capital	=		0.09822											
					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	)	
	=	(	0.07492	+(	(50,619)	+	48,967	) /	70,988,955	)	x	0.35	)	
		(	1								-	0.35	)	
	=		0.0403290											
					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	)	
	=	(	0.07492	+(	(50,619)	+	48,967	) /	70,988,955	)	+	0.0403290	)*	0.0893
		(	1								-	0.0893	)	
	=		0.0112986											
(a)+(b)+(c) **Cost of Capital Rate**	=		0.1498476											

		(PTF)
INVESTMENT BASE	$	70,988,955
x Cost of Capital Rate		0.1498476
= Investment Return and Income Taxes		10,637,524

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/09

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	-			-		111,787,718	(d)	w/s 5, line 1
2	General Plant	157,464,647	8.7645%	(a)	13,800,989	23.5592%	3,251,403		w/s 17, line 5
3	Total (line 1+2)				13,800,989		115,039,121		
4	Transmission Plant Held for Future Use	17,514,583			17,514,583	23.5592%	4,126,296		Page 214, lines 4+8+9+25
	Transmission Accumulated Depreciation								
5	Transmission Accum. Depreciation	(167,830,327)			(167,830,327)	23.5592%	(39,539,482)		w/s 17, line 4
6	General Plant Accum.Depreciation	(80,859,219)	8.7645%	(a)	(7,086,906)	23.5592%	(1,669,618)		w/s 17, line 7
7	Total (line 6+7)	(248,689,546)			(174,917,233)		(41,209,100)		
	Transmission Accumulated Deferred Taxes								
8	Accumulated Deferred Taxes (281-283)	(69,049,645)			(69,049,645)	23.5592%	(16,267,544)		See p. 450 notes for pages 274 & 276
9	Accumulated Deferred Taxes (190)	30,932,629			30,932,629	23.5592%	7,287,480		See p. 450 notes for page 234
10	Total (line 8+9)	(38,117,016)			(38,117,016)		(8,980,064)		
11	Unamortized loss on Reacquired Debt	4,510,860	29.2322%	(c)	1,318,624	23.5592%	310,657		Page 111.81c
	Other Regulatory Assets								
12	FAS 106	15,677,963	8.7645%	(a)	1,374,095			Page 232, line 25f & P.232, line 3f	
13	FAS 109	-							DITs functionalized in FF 1 excluding FAS109 DITs, therefore the 109 reg asset is properly excluded.
14	Total (line 12+13)	15,677,963			1,374,095	23.5592%	323,726		
15	Transmission Prepayments	3,888,271	8.7645%	(a)	340,788	23.5592%	80,287		FF I 111.57c
16	Transmission Materials and Supplies	2,918,554			2,918,554	23.5592%	687,588		See note for page 227.11c on Page 450
17	Cash Working Capital								
18	Operation & Maintenance Expense						3,415,913		Worksheet 1, Line 21
19	Administrative & General Expense						1,285,780		Worksheet 1, Line 22
20	Net Transmission Support Expense						181,856		Worksheet 7, Line 13b
21	Subtotal (line 18+19+20)						4,883,549		
22							0.125		x 45 / 360
23	Total (line 21 * line 22)						610,444		

(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 12/31/09

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	11,789,157			11,789,157	23.5592%	2,777,431	w/s 17, line 2
2	General Depreciation	4,057,438	8.7645%	(a)	355,614	23.5592%	83,780	w/s 17, line 6
3	Total (line 1+2)				12,144,771		2,861,211	
4	Amortization of Loss on Reacquired Debt	718,290	29.2322%	(c)	209,972	23.5592%	49,468	Page 117.64c
5	Amortization of Investment Tax Credits	(735,000)	29.2322%	(c)	(214,857)	23.5592%	(50,619)	Page 266.8f
	Property Taxes							
6	Transmission Property Taxes	4,289,946			4,289,946	23.5592%	1,010,677	See note for p. 262.14i on page 450.1
7	General Property Taxes	-	8.7645%	(a)	-	23.5592%	-	
8	Total (line 1+2)	4,289,946			4,289,946		1,010,677	
9	Payroll Taxes	-	-	(d)	-	-	-	
	Transmission Operation and Maintenance							
10	Operation and Maintenance	98,972,652						w/s 17, line 8
11	Transmission of Electricity by Others - #565	79,406,286						Page 321.96b/332/ws 11, line 17
12	Load Dispatching - #561 - 561.4	4,547,254						Page 321.84-88b
13	**Station Expenses & Rents - #562 / #567	519,838						ws 11, line 25
14	O&M - line 10 less lines 11, 12, & 13	14,499,274			14,499,274	23.5592%	3,415,913	
	Transmission Administrative and General							
15	A & G subject to Wage & Salaries Allocation Factor	41,255,126	8.7645%	(a)	3,615,806			w/s 9, line 28
16	A & G subject to Plant Allocation Factor	292,411	29.2322%	(c)	85,478			w/s 9, line 31
17	A & G directly assigned to transmission	1,756,372	100.00%		1,756,372			w/s 9, lines 14 & 17
18	A&G (line)	43,303,909			5,457,656	23.5592%	1,285,780	

(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 12/31/09

Line No.			RNS Rate Worksheet or FERC Form 1 Reference
	PTF Transmission Plant Allocation Factor		
		Pre 1997	
1	PTF Transmission Investment	111,787,718	w/s 15
2	Total Transmission Investment	474,496,934	w/s 17, line 3 & w/s 15
3	Percent Allocation (line 1/2)	23.5592%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	4,141,340	w/s 17, line 1
5	Affiliated Company Transmission Wages and Salaries	-	
6	Total Transmission Wages and Salaries (line 4+ 5)	4,141,340	
7	Total Wages and Salaries	56,734,062	Page 354.28b + line 5
8	Administrative and General Wages and Salaries	9,483,001	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)	47,251,061	
11	Percent Allocation (line 6/10)	8.7645%	
	Plant Allocation Factor		
12	Total Transmission Investment (excluding capital leases)	474,496,934	ws 5 line 2
13	Transmission Related General Plant	13,800,989	ws 3 line 2
14	Total Transmission Related Plant	488,297,923	
15	Total Electric Plant in Service (excludes capital leases)	1,670,410,851	Page 207.104g
16	Percent Allocation (line 14/15)	29.2322%	

Affiliated Company Wages and Salaries

Line					
"Affiliated" Transmission Wages and Salaries			Transmission Wages by 3 digit FERC		
#560 - 573					
			560	764,431	
1	560	-	561-561.4	2,084,929	w/s 17 line 1b
			561.5-561.8	90,515	
2	562	-	562	481,019	
3	564	-	563	105,408	
4	566	-	564	783	
5	568	-	566	800,787	
			567	-	
6	569	-	568	185,001	
7	570	-	569	88,981	
8	571	-	570	1,362,626	
9	572	-	571	175,606	
10	573	-	572	83,807	
11 = 1 thru 10	Total Transmission	-	573	2,376	
				6,226,269	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 12/31/09

			CENTRAL MAINE POWER CO.		
	Participant	PTF Supporting Facilities	Revenues	Expenses	
			(a)	(b)	
1	Boston Edison:	HQ Phase II - AC in MA		35,959	1
2	Central Maine Power:	345 kV Buxton-South Gorham 386 line	358,365		2
3		115 kV Wyman 164-167 lines	146,146		3
4		115 kV Maine Yankee transmission	-		4
5		50% of double steel towers # 30-46 (sec 375)	5,455		5
6					6
7	New England Power:	Chester SVC		214,803	7
8		HQ Phase II - AC in MA		441,061	8
9					9
10					10
11		Total =	509,966	691,822	11
12					12
13		Net Support (line 11b - 11a)		181,856	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.

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	1,384,149	1,328,897	1,312,754	1,155,482	1,168,518	1,247,108	1,394,113	1,503,494	1,212,288	1,246,093	1,284,757	1,427,108	1,305,397
Fox Island (NP)	1,674	1,673	1,598	1,383	1,550	1,515	1,692	1,834	1,726	1,609	1,548	1,387	1,599
Kennebunk (NP)	16,874	16,824	16,739	14,397	13,538	13,424	16,075	18,255	13,842	14,250	15,360	17,083	15,555
Gates Formed Fiber (NP)	633	1,360	1,429	1,347	2,019	2,075	1,885	2,000	1,429	1,257	2,028	2,098	1,630
Madison Electric Works	6,017	5,736	5,645	4,302	4,385	4,003	4,613	4,620	4,095	4,753	5,243	5,899	4,943
FPL-Madison	44,390	45,060	35,770	45,760	50,360	52,930	50,940	36,840	44,840	44,240	43,890	48,460	45,290
Westbrook Energy Center	-	-	-	-	-	-	-	-	-	-	-	-	-
FPL Energy	2,534	866	10,576	2,479	4,940	2,354	2,255	1,197	2,027	2,217	2,341	2,551	3,028
Total	1,456,271	1,400,416	1,384,511	1,225,150	1,245,310	1,323,409	1,471,573	1,568,240	1,280,247	1,314,419	1,355,167	1,504,586	1,377,442

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/09

	Acc't	Description	Amount		
1	920	Administrative and General Salaries	8,970,419		
2	921	Office Supplies and Expenses	2,185,552		
3	922	Less Administrative Expenses Transferred	(610,667)		
4	923	Outside Services	16,856,767		
5	924	Property Insurance	292,411		
6	925	Injuries and Damages	2,752,571		
7	926	Employee Pensions and Benefits	(1,337,609)		
8	928	Regulatory Commissions Expense	5,362,384		-
9	930.1	General Advertising	924,630		
10	930.2	Miscellaneous General Expense	9,701,986		
11	931	Rents	738,055		
12	935	Maintenance of General Plant	1,998,052		
13		Total Admin & Gen'l Exp.	47,834,551		Page 323.197b
14		FERC assessments - Transmission (directly assigned)	1,484,660		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)	1,484,660		FF1 page 350.d
17		State assessments - Transmission (directly assigned)	271,712		FF1 page 350.d
18		Total State Assessments	3,877,724		FF1 page 350.d
19	928	Total Regulatory Commissions Expense: (16+18) & from line 8	5,362,384		FF1 page 350.d, line 46
20		General Advertising - Transmission related	-		
21		Non-Transmission related General Advertising Exp.	924,630		
22	930.1	Total General Advertising Exp. (line 9)	924,630		
		Summary of Attachment F treatment of A&G			
23		Total A&G (line 13)	47,834,551		
24	924	less Property Insurance (line 5)	(292,411)		
25	928	less Regulatory Commissions Exp. (line 19)	(5,362,384)		
26	930.1	less Non-Trans. General Advertising Exp. (line 9)	(924,630)		
27	920-935	less EPRI Expenses	-		
28		A&G subject to Wages and Salaries Allocation Factor:	41,255,126		to worksheet 4, line 15, column 1
29		Property Insurance (line 5)	292,411		
30		Regulatory Commissions Exp. - FERC assessments (line 15)	-		
31		Total A&G subject to Plant Allocation Factor	292,411		to worksheet 4, line 16, column 1

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/09

	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)	($5,455)	-	($5,455)	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)	(146,146)	-	(146,146)	454
4	WF Wyman #4 Joint Owners	Section 386	ws 7, line 2, col. (a)	(358,365)	(514,207)	(872,572)	454
5	FPL			-	(145,214)	(145,214)	454
6	PSNH	Section 214 (from Kimball Rd substation)		-	(60,729)	(60,729)	454
7							
8		Total Support Revenues	ws 7, line 11, col. (a)	($509,966)	($720,150)	($1,230,116)	
9							
10		**Wheeling**					
11	Jurisdictional Sales			(115,129,862)	$ -	(115,129,862)	
12	RNS, TOUT, Sch 1			(45,487,212)	-	(45,487,212)	456
13	HVDC - Sch 20A-CMP				(5,918,212)	(5,918,212)	456
14							
15		Total Wheeling Revenues		($160,617,074)	($5,918,212)	($166,535,286)	FF 1 page 330, col n.
16							
17		Total Transmission Wheeling/Support Revenues		($161,127,040)	($6,638,362)	($167,765,402)	
18							
19							
20							
21	RNS			40,130,799	450 Notes for FF1 p.328, line 24		
22	SCH 1			3,817,802			
23	TOUT			1,538,612			
24	TOTAL		line 12, above	45,487,213			

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/09

	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	$ 35,959	-	$35,959	566
2	NEP	NEP Ph II, AC -O&M		152,870	-	$152,870	566
3		NEP Ph II, AC -RENTS		116,207	-	$116,207	567
4		NEP Ph II, AC -INTEREST		171,984	-	$171,984	431
5		NEP Ph II, AC -TOTAL	ws 7, line 8, col b	441,061	-	$441,061	
6		NHH- Chester SVC	ws 7, line 7, col b	214,803	-	$214,803	566
7							
8		Total Support Expenses	ws 7, line 11, col b	$ 691,822	-	$691,822	
9							
10		**Wheeling**					
11							
12	ISO-NE	Charges under the OATT		77,085,897		$77,085,897	lines 28-35 below
13	Bangor Hydro	Firm PTP Reservation for Energy Transferred to Herman Sta.		-	303,271	$303,271	565 FF1 pg 332, line 4
14	ISO-NE	Sch 1 - Part IV of ISO-NE Tariff		1,586,121		$1,586,121	see below
15	PSNH	Bolt Hill		430,997		$430,997	565010 F1 pg 332, line 2
16							
17		Total Wheeling Expenses		$79,103,015	$303,271	$79,406,286	FERC Form 1 page 332
18							
19		Total Transmission Wheeling/Support Expenses		$79,794,837	$303,271	$80,098,108	
20							
21		SUMMARY BY FERC ACCOUNT:					
22		431				$ 171,984	
23		565				79,406,286	FERC Form 1 page 332
24		566				403,631	
25		567	(566+567 to ws 4, line 13)		519,838	116,207	
26		TOTAL				$ 80,098,108	
27							
28	RNS					$ 71,830,556	450.1 Notes for FFI p.332.6
29	Sch 1					1,891,826	450.1 Notes for FFI p.332.6
30	Sch 2 -CC					1,512,460	450.1 Notes for FFI p.332.6
31	Sch 2 -VAR Uplift					740,948	450.1 Notes for FFI p.332.6
32	Congestion Uplift					-	450.1 Notes for FFI p.332.6
33	Sch 16					723,479	450.1 Notes for FFI p.332.6
34	Load Response					341,129	450.1 Notes for FFI p.332.6
35	Sch 5-NESCO					45,499	450.1 Notes for FFI p.332.6
36	ISO-NE Sch 1					1,586,121	450.1 Notes for FFI p.332.6
37	Total					$ 78,672,018	565 FF1 pg 332, line 6.h.

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/09

		CAPITALIZATION 12/31/2009	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
MED-TERM NOTES	page 123.9	443,200,000	33.567%	6.697%		
POLLUTION CONTROL NOTES	page 123.9	19,500,000	1.477%	5.594%		
FAME		-	0.000%	0.000%		
MORTGAGE BONDS		-	0.000%	0.000%		
TOTAL LONG-TERM DEBT	page 112.21c	462,700,000	35.044%	6.648%	2.330%	
PREFERRED STOCK	page 123.11 and page 112.3c	13,571,300	1.028%	4.993%	0.051%	0.051%
COMMON EQUITY	page 112.16c less line 3c	844,058,753	63.928%	11.640%	7.441%	7.441%
TOTAL INVESTMENT RETURN		1,320,330,053	100.00%		9.822%	7.492%

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/09

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%
TOTALS	430,621,754	7,369,650	1.71%
Depreciation Exp from w/s 1			2,861,211
AFUDC adj to w/s 2			48,967

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/09

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	5,781,214	
101103	NEETCO HQDC	-	
101104	VETCO HQDC	-	
101105	NEP HQAC	2,736,421	
101106	NHH HQDC	2,428,680	
101107	NEH HQDC	4,064,198	
TOTAL CAPITAL LEASES		$ 15,010,512	Page 112.26+113.49

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/09

		PTF pre 1997	PTF post 1996	Total PTF	Non-PTF	Total Transmission	
TRANSMISSION LINES	77,352,034		66,742,299	144,094,332	70,697,967	214,792,300	
SUBSTATIONS	35,085,477		110,440,607	145,526,084	116,936,677	262,462,761	
TOTALS		112,437,510	177,182,906	289,620,416	187,634,644	477,255,061	
Balance per FERC Form 1; p. 207, line 58g		112,437,510	177,182,906	289,620,416	187,634,644	477,255,061	
Less SCADA & RTUs directly assigned to Schedule 1		649,792	1,023,966	1,673,758	1,084,368	2,758,126	
Totals for RNS		111,787,718	176,158,940	287,946,658	186,550,276	474,496,934	
PRE 1997 PTF - from above						$ 111,787,718	to w/s 5, line 1
POST 1996 PTF - from above						176,158,940	to Post 96 w/s 5, line 1
Total PRE 97 AND POST 96 PTF						$ 287,946,658	Total PTF Investment for RNS

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/09

PROPERTY DESCRIPTION	PROPERTY CLASSIFICATION	COST	ref	RESERVE	ref	DEPRECIATION	ref
Furniture & Equipment	General	266,008		124,178		10,450	
Structure Costs & Map Boards	General	3,750,352		1,454,331		91,884	
UPS	General	284,858		137,575		10,550	
EMS Hardware	General	1,834,871		1,095,978		203,854	
LMS	General	-		-		-	
EBCC	General	-		-		-	
Communication Equipment	General	815,265		545,908		59,677	
PC Equipment	General	42,476		30,034		524	
		6,993,829	w/s 17,5b	3,388,004	w/s 17,7b	376,939	w/s 17,6b
EMS Software	Intangibile	7,900,188		7,364,597		676,571	
S/S RTU's & Scada	Transmission	2,758,126	w/s 17,3b	947,417	w/s 17,4b	69,505	w/s 17,2b
Total Plant Directly Assigned to Schedule 1		17,652,144		11,700,018		1,123,015	

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/09

		A	B	C	D		
		FERC FORM 1TOTAL	LESS COST RECOVERED UNDER SCH 1	LESS COSTS INCURRED UNDER THE ISO TARIFF	ADJUSTED TOTAL		WORKSHEET REFERENCE FOR COL. D
	WAGES & PAYROLL EXPENSES						
1	FERC FORM 1, PG. 354, LINE 21B	6,226,269	(2,084,929)	-	4,141,340	1	WS 5, LINE 4
	TRANSMISSION DEPRECIATION EXP						
2	FERC FORM 1, PG. 336, LINE 7B	11,858,662	(69,505)	-	11,789,157	2	WS 4, LINE 1
	TOTAL TRANSMISSION PLANT						
3	FERC FORM 1, PG. 207, LINE 58G	477,255,061	(2,758,126)	-	474,496,934	3	WS 5, LINE 2
	TRANSMISSION PLANT DEPREC. RES.						
4	FERC FORM 1, PG 219, LINE 25c	168,777,744	(947,417)	-	167,830,327	4	WS 3, LINE 5
	TOTAL GENERAL PLANT						
5	FERC FORM 1, PG 207, LINE 99g	164,458,476	(6,993,829)	-	157,464,647	5	WS 3, LINE 2
	GENERAL DEPRECIATION EXPENSE						
6	FERC FORM 1, PG. 336, LINE 10b	4,434,377	(376,939)	-	4,057,438	6	WS 4, LINE 2
	GENERAL DEPRECIATION RESERVE						
7	FERC FORM 1, PG 219, LINE 28c	84,247,223	(3,388,004)	-	80,859,219	7	WS 3, LINE 6
	Transmission O&M						
8	FERC Form 1, pg 321, line 112	98,972,652	-		98,972,652	8	WS 4, LINE 10

CENTRAL MAINE POWER COMPANY
PRE-97 RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/09

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 12/31/09

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 12/31/09

	Short Term Through and Out Revenues			
	From Worksheet 10, line 30	1,538,612		
		-		
	Short-Term & Non-Firm T&O	1,538,612	(Per G/L)	
	PTF BALANCE (see w/s 15)	% OF TOTAL	allocation of T/O Revenues	
PRE 1997 PTF	111,787,718	38.82%	597,326	
POST 96 PTF	176,158,940	61.18%	941,286	
TOTAL	287,946,658	100.00%	1,538,612	

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/09

Line No.			Attachment F Reference Section:		Reference
	II.	INVESTMENT BASE			
1		Transmission Plant	II (A)(1)(a)	$ 176,158,940	Worksheet 3, line 1 column 5
2		General Plant	II (A)(1)(b)	5,123,672	Worksheet 3, line 2 column 5
3		Plant Held For Future Use	II (A)(1)(c)	6,502,359	Worksheet 3, line 4 column 5
4		Total Plant (Lines 1+2+3)		187,784,971	
5		Accumulated Depreciation	II (A)(1)(d)	64,938,722	Worksheet 3, line 7 column 5
6		Accumulated Deferred Income Taxes	II (A)(1)(e)	14,151,095	Worksheet 3, line 10 column 5
7		Loss On Reacquired Debt	II (A)(1)(f)	489,544	Worksheet 3, line 11 column 5
8		Other Regulatory Asssets	II (A)(1)(g)	510,138	Worksheet 3, line 14 column 5
9		Net Investment (Line 4-5-6+7+8)		109,694,836	
10					
11		Prepayments	II (A)(1)(h)	126,519	Worksheet 3, line 15 column 5
12		Materials & Supplies	II (A)(1)(i)	1,083,525	Worksheet 3, line 16 column 5
13		Cash Working Capital	II (A)(1)(j)	926,136	Worksheet 3, line 23 column 5
14		Total Investment Base (Line 9+11+12+13)		$ 111,831,016	
	II.	REVENUE REQUIREMENTS			
15		Investment Return and Income Taxes	II (A)	$ 17,661,877	Worksheet 2
16		Depreciation Expense	II (B)	4,508,795	Worksheet 4, line 3 column 5
17		Amortization of Loss on Reacquired Debt	II (C)	77,953	Worksheet 4, line 4 column 5
18		Investment Tax Credit	II (D)	(79,767)	Worksheet 4, line 5 column 5
19		Municipal Taxes	II (E)	1,592,660	Worksheet 4, line 8 column 5
20		Payroll Taxes	II (F)	-	Worksheet 4, line 9 column 5
21		Operation & Maintenance Expense	II (G)	5,382,913	Worksheet 4, line 14 column 5
22		Administrative & General Expense	II (H)	2,026,177	Worksheet 4, line 18 column 5
23		Transmission Related Integrated Facilities Charge	II (I)	-	
24		Transmission Support Revenue	II (J)	-	Worksheet 7, line 11 column a
25		Transmission Support Expense	II (K)	-	Worksheet 7, line 11 column b
26		Transmission Related Expense from Generators	II (L)	-	
27		Taxes and Fees	II (M)	-	
28		Revenues for TOUT Transmission Service	II (N)	(941,286)	W/S 20
29		Transmission Rents Received from Electric Property	II (O)	-	
30		Total Revenue Requirements (Line 15 thru 29)		$ 30,229,322	
		Forecasted Transmission Revenue Requirements - 2010		33,727,217	W/S 16, line 8
		Total - 2009 Actual + 2010 Forecasted		$ 63,956,539	

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/09

				CAPITALIZATION		CAPITALIZATION		COST OF		COST OF		EQUITY				
	see w/s 8 - capitalization					RATIOS		CAPITAL		CAPITAL		PORTION				
1	LONG-TERM DEBT		$	462,700,000		35.044%		6.648%		2.330%						
2	PREFERRED STOCK			13,571,300		1.028%		4.993%		0.051%		0.051%				
3	COMMON EQUITY			844,058,753		63.928%		11.640%		7.441%		7.441%				
4																
5	TOTAL INVESTMENT RETURN		$	1,320,330,053		100.00%				9.822%		7.492%				
6																
7	New Inv Adder Calc. (100 bp)					63.928%		1.00%		0.639%		0.639%	1.079%	including FIT&SIT		
8	MPRP New Inv Adder Calc. (125 bp)					63.928%		1.25%		0.799%		0.799%	1.350%	including FIT&SIT		
9	**Cost of Capital Rate=**															
10																
11	(a) Weighted Cost of Capital	=		0.09822												
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		=	(	0.07492	+(	(79,767)	+	77,163	) /	111,831,016	)	x	0.35		)	
18			(	1								-	0.35		)	
19																
20		=		0.0403290												
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		=	(	0.07492	+(	(79,767)	+	77,163	) /	111,831,016	)	+	0.0403290		)*	0.0893
27			(	1								-	0.0893		)	
28																
29		=		0.0112986												
30																
31																
32																
33	(a)+(b)+(c) **Cost of Capital Rate**	=		0.1498476												
34																
35																
36																
37																
38				**Post 96 (PTF)**		**post 2003 RSP ptf (Incremental Return Calc)**		**MPRP PTF (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		$	111,831,016		60,992,119		18,216,269								
41																
42	x Cost of Capital Rate			14.98476%		1.07947%		1.34976%								
43																
44	= Investment Return and Income Taxes			16,757,609		658,392		245,876		17,661,877	w/s 1 line 15					

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/09

Investment Base Calculation for Incremental Return and Associated Income Taxes for Post-2003 PTF

		RSP PTF	
		MPRP PTF	**In Service by 12/31/08**
1	Investment 22,529,338	$	$ 76,553,578
2	Depreciation Reserve	(266,621)	(3,516,331)
3	Accumulated Deferrred Income Taxes	(4,046,448)	(12,045,128)
4			
5	INVESTMENT BASE	$ 18,216,269	$ 60,992,119
		w/s 2 line 40	w/s 2 line 40

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/09

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	-			-		176,158,940	(d)	w/s 5, line 1
2	General Plant	157,464,647	8.7645%	(a)	13,800,989	37.1254%	5,123,672		w/s 12, line 5
3	Total (line 1+2)				13,800,989		181,282,612		
4	Transmission Plant Held for Future Use	17,514,583			17,514,583	37.1254%	6,502,359		Page 214, lines 4+8+9+25
	Transmission Accumulated Depreciation								
5	Transmission Accum. Depreciation	(167,830,327)			(167,830,327)	37.1254%	(62,307,680)		w/s 12, line 4
6	General Plant Accum.Depreciation	(80,859,219)	8.7645%	(a)	(7,086,906)	37.1254%	(2,631,042)		w/s 12, line 7
7	Total (line 6+7)	(248,689,546)			(174,917,233)		(64,938,722)		
	Transmission Accumulated Deferred Taxes								
8	Accumulated Deferred Taxes (281-283)	(69,049,645)			(69,049,645)	37.1254%	(25,634,957)		See p. 450 notes for pages 274 & 276
9	Accumulated Deferred Taxes (190)	30,932,629			30,932,629	37.1254%	11,483,862		See p. 450 notes for page 234
10	Total (line 8+9)	(38,117,016)			(38,117,016)		(14,151,095)		
11	Unamortized loss on Reacquired Debt	4,510,860	29.2322%	(c)	1,318,624	37.1254%	489,544		Page 111.81c
	Other Regulatory Assets								
12	FAS 106	15,677,963	8.7645%	(a)	1,374,095				Page 232, line 25f & P.232, line 3f
13	FAS 109	-							DITs functionalized in FF 1 excluding FAS109 DITs, therefore the 109 reg asset is properly excluded.
14	Total (line 12+13)	15,677,963			1,374,095	37.1254%	510,138		
15	Transmission Prepayments	3,888,271	8.7645%	(a)	340,788	37.1254%	126,519		FF I 111.57c
16	Transmission Materials and Supplies	2,918,554			2,918,554	37.1254%	1,083,525		See note for page 227.11c on Page 450
17	Cash Working Capital								
18	Operation & Maintenance Expense						5,382,913		Worksheet 1, Line 21
19	Administrative & General Expense						2,026,177		Worksheet 1, Line 22
20	Net Transmission Support Expense						-		
21	Subtotal (line 18+19+20)						7,409,090		
22							0.125		x 45 / 360
23	Total (line 21 * line 22)						926,136		
24	MPRP CWIP	0					0		
	(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 12/31/09

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	11,789,157			11,789,157	37.1254%	4,376,772	w/s 12, line 2
2	General Depreciation	4,057,438	8.7645%	(a)	355,614	37.1254%	132,023	w/s 12, line 6
3	Total (line 1+2)				12,144,771		4,508,795	
4	Amortization of Loss on Reacquired Debt	718,290	29.2322%	(c)	209,972	37.1254%	77,953	Page 117.64c
5	Amortization of Investment Tax Credits	(735,000)	29.2322%	(c)	(214,857)	37.1254%	(79,767)	Page 266.8f
	Property Taxes *							
6	Transmission Property Taxes	4,289,946			4,289,946	37.1254%	1,592,660	See note for p. 262.14i on page 450.1
7	General Property Taxes	-	8.7645%	(a)		37.1254%	-	
8	Total (line 1+2)	4,289,946			4,289,946		1,592,660	
9	Payroll Taxes	-	-	(d)	-	-	-	
	Transmission Operation and Maintenance							
10	Operation and Maintenance	98,972,652						w/s 12, line 8
11	Transmission of Electricity by Others - #565	79,406,286						Page 321.96b/332/pre97 ws 11, line 17
12	Load Dispatching - #561	4,547,254						Page 321.84-88b
13	**Station Expenses & Rents - #562 / #567	519,838						Pre 1997 ws 11, line 25
14	O&M - line 10 less lines 11, 12, & 13	14,499,274			14,499,274	37.1254%	5,382,913	
	Transmission Administrative and General							
15	A & G subject to Wage & Salaries Allocation Factor	41,255,126	8.7645%	(a)	3,615,806			w/s 7, line 28
16	A & G subject to Plant Allocation Factor	292,411	29.2322%	(c)	85,478			w/s 7, line 31
17	A & G directly assigned to transmission	1,756,372	100.00%		1,756,372			w/s 7, line 14
18	A&G (line 14+15)	43,303,909			5,457,656	37.1254%	2,026,177	

* 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 12/31/09

Line No.			RNS Rate Worksheet or FERC Form 1 Reference
	PTF Transmission Plant Allocation Factor		
		Post 1996	
1	PTF Transmission Investment	176,158,940	w/s 10
2	Total Transmission Investment	474,496,934	w/s 12, line 3 & w/s 10
3	Percent Allocation (line 1/2)	37.1254%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	4,141,340	w/s 12, line 1
5	Affiliated Company Transmission Wages and Salaries	-	
6	Total Transmission Wages and Salaries (line 4+ 5)	4,141,340	
7	Total Wages and Salaries	56,734,062	Page 354.28b + line 5
8	Administrative and General Wages and Salaries	9,483,001	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)	47,251,061	
11	Percent Allocation (line 6/10)	8.7645%	
	Plant Allocation Factor		
12	Total Transmission Investment (excluding capital leases)	474,496,934	ws 5 line 2
13	Transmission Related General Plant	13,800,989	ws 3 line 2
14	Total Transmission Related Plant	488,297,923	
15	Total Electric Plant in Service (excluding capital leases)	1,670,410,851	Page 207.104g
16	Percent Allocation (line 14/15)	29.2322%	

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/09

Affiliated Company Wages and Salaries

Line				
"Affiliated" Transmission Wages and Salaries			Transmission Wages by 3 digit FERC		
#560 - 573					
			560	764,431	
1	560	-	561-561.4	2,084,929	w/s 12 line 1b
2	562	-	561.5-561.8	90,515	
3	564	-	562	481,019	
4	566	-	563	105,408	
5	568	-	564	783	
6	569	-	566	800,787	
7	570	-	567	-	
8	571	-	568	185,001	
9	572	-	569	88,981	
10	573	-	570	1,362,626	
11 = 1 thru 10	Total Transmission	-	571	175,606	
			572	83,807	
			573	2,376	
				6,226,269	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 12/31/09

	Acc't	Description	Amount		
1	920	Administrative and General Salaries	8,970,419		
2	921	Office Supplies and Expenses	2,185,552		
3	922	Less Administrative Expenses Transferred	(610,667)		
4	923	Outside Services	16,856,767		
5	924	Property Insurance	292,411		
6	925	Injuries and Damages	2,752,571		
7	926	Employee Pensions and Benefits	(1,337,609)		
8	928	Regulatory Commissions Expense	5,362,384		
9	930.1	General Advertising	924,630		
10	930.2	Miscellaneous General Expense	9,701,986		
11	931	Rents	738,055		
12	935	Maintenance of General Plant	1,998,052		
13		Total Admin & Gen'l Exp.	47,834,551		Page 323.197b
14		FERC assessments - Transmission (directly assigned)	1,484,660		to worksheet 4, line 17, column 5
15		FERC assessments - subject to plant allocation factor	-		FF1 page 350.d
16		TOTAL FERC ASSESSMENTS (14+15)	1,484,660		FF1 page 350.d
17		State assessments - Transmission (directly assigned)	271,712		FF1 page 350.d
18		Total State Assessments	3,877,724		FF1 page 350.d
19	928	Total Regulatory Commissions Expense: (16+18) & from line 8	5,362,384		FF1 page 350.d, line 46
20		General Advertising - Transmission related	-		
21		Non-Transmission related General Advertising Exp.	924,630		
22	930.1	Total General Advertising Exp. (line 9)	924,630		
		Summary of Attachment F treatment of A&G			
23		Total A&G (line 13)	47,834,551		
24	924	less Property Insurance (line 5)	(292,411)		
25	928	less Regulatory Commissions Exp. (line 19)	(5,362,384)		
26	930.1	less Non-Trans. General Advertising Exp. (line 9)	(924,630)		
27	920-935	less EPRI Expenses	-		
28		A&G subject to Wages and Salaries Allocation Factor:	41,255,126		to worksheet 4, line 15, column 1
29		Property Insurance (line 5)	292,411		
30		Regulatory Commissions Exp. - FERC assessments (line 15)	-		
31		Total A&G subject to Plant Allocation Factor	292,411		to worksheet 4, line 16, column 1

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/09

		CAPITALIZATION 12/31/2009	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
MED-TERM NOTES	page 123.10	443,200,000	33.567%	6.697%		
POLLUTION CONTROL NOTES	page 123.10	19,500,000	1.477%	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	35.044%	6.648%	2.330%	
PREFERRED STOCK	page 123.11 and page 112.3c	13,571,300	1.028%	4.993%	0.051%	0.051%
COMMON EQUITY	page 112.16c less line 3c	844,058,753	63.928%	11.640%	7.441%	7.441%
TOTAL INVESTMENT RETURN		1,320,330,053	100.00%		9.822%	7.492%

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/09

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%
TOTALS	430,621,754	7,369,650	1.71%
Depreciation Exp from w/s 1			4,508,795
AFUDC adj to w/s 2			77,163

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/09

		PTF		Total PTF	Non-PTF	Total Transmission	
		pre 1997	post 1996				
TRANSMISSION LINES	77,352,034		66,742,299	144,094,332	70,697,967	214,792,300	
SUBSTATIONS	35,085,477		110,440,607	145,526,084	116,936,677	262,462,761	
TOTALS		112,437,510	177,182,906	289,620,416	187,634,644	477,255,061	
Balance per FERC Form 1; p. 207, line 53g		112,437,510	177,182,906	289,620,416	187,634,644	477,255,061	
Less SCADA & RTUs directly assigned to Schedule 1		649,792	1,023,966	1,673,758	1,084,368	2,758,126	
Totals for RNS		111,787,718	176,158,940	287,946,658	186,550,276	474,496,934	
PRE 1997 PTF - from above						$ 111,787,718	to Pre97 w/s 5, line 1
POST 1996 PTF - from above						176,158,940	to w/s 5, line 1
Total PRE 97 AND POST 96 PTF						$ 287,946,658	Total PTF Investment for RNS

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/09

PROPERTY DESCRIPTION	PROPERTY CLASSIFICATION	COST	ref	RESERVE	ref	DEPRECIATION	ref
Furniture & Equipment	General	266,008		124,178		10,450	
Structure Costs & Map Boards	General	3,750,352		1,454,331		91,884	
UPS	General	284,858		137,575		10,550	
EMS Hardware	General	1,834,871		1,095,978		203,854	
LMS	General	-		-		-	
EBCC	General	-		-		-	
Communication Equipment	General	815,265		545,908		59,677	
PC Equipment	General	42,476		30,034		524	
		6,993,829	w/s 17,5b	3,388,004	w/s 17,7b	376,939	w/s 17,6b
EMS Software	Intangibile	7,900,188		7,364,597		676,571	
S/S RTU's & Scada	Transmission	2,758,126	w/s 17,3b	947,417	w/s 17,4b	69,505	w/s 17,2b
Total Plant Directly Assigned to Schedule 1		17,652,144		11,700,018		1,123,015	

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/09

		A	B	C	D		
		FERC FORM 1TOTAL	LESS COST RECOVERED UNDER SCH 1	LESS COSTS INCURRED UNDER THE NOATT OR ISO TARIFF	ADJUSTED TOTAL		WORKSHEET REFERENCE FOR COL. D
	WAGES & PAYROLL EXPENSES						
1	FERC FORM 1, PG. 354, LINE 21B	6,226,269	(2,084,929)	-	4,141,340	1	WS 5, LINE 4
	TRANSMISSION DEPRECIATION EXP						
2	FERC FORM 1, PG. 336, LINE 7B	11,858,662	(69,505)	-	11,789,157	2	WS 4, LINE 1
	TOTAL TRANSMISSION PLANT						
3	FERC FORM 1, PG. 207, LINE 53G	477,255,061	(2,758,126)	-	474,496,934	3	WS 5, LINE 2
	TRANSMISSION PLANT DEPREC. RES.						
4	FERC FORM 1, PG 219, LINE 23c	168,777,744	(947,417)	-	167,830,327	4	WS 3, LINE 5
	TOTAL GENERAL PLANT						
5	FERC FORM 1, PG 207, LINE 99g	164,458,476	(6,993,829)	-	157,464,647	5	WS 3, LINE 2
	GENERAL DEPRECIATION EXPENSE						
6	FERC FORM 1, PG. 336, LINE 10b	4,434,377	(376,939)	-	4,057,438	6	WS 4, LINE 2
	GENERAL DEPRECIATION RESERVE						
7	FERC FORM 1, PG 219, LINE 28c	84,247,223	(3,388,004)	-	80,859,219	7	WS 3, LINE 6
	Transmission O&M						
8	FERC Form 1, pg 321, line 112b	98,972,652	-		98,972,652	8	WS 4, LINE 10

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/09

Through and Out Revenues				
From Pre97 Worksheet 10, line 30		`		
		#VALUE!		
Short-Term & Non-Firm T&O		1,538,612	(Per G/L)	
	PTF BALANCE (see w/s 15)	% OF TOTAL	allocation of T/O Revenues	
PRE 1997 PTF	111,787,718	38.82%	597,326	
POST 96 PTF	176,158,940	61.18%	941,286	
TOTAL 287,946,658		100.00%	1,538,612	

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/09

	Investment	2009 Activity				Investment
	as of 12/31/08	Additions	Retires	Transfers	Adjustments	as of 12/31/09
115kV Lines - Excluding Land						
60	$ 909,538	$ 23,780	$ (1,797)	$ 15,000	$ -	$ 946,521
61A	852,175	-	-	-	-	852,175
61	2,549,324	-	-	24,475	-	2,573,799
62	484,721	-	(32)	-	-	484,689
63	1,769,815	30,657	(490)	4,378	-	1,804,359
64	552,496	(2,100)	(1,208)	47,992	-	597,180
65	291,200	-	-	-	-	291,200
66	1,036,836	3,982	-	5,861	-	1,046,679
67	4,621,218	-	(58,262)	(44,983)	-	4,517,973
68	4,298,364	1,441	-	17,169	-	4,316,974
69	2,995,119	4,591	(742)	(669)	-	2,998,299
75	1,112,359	-	(3,812)	329	-	1,108,877
80	1,868,878	(3,737)	(2,423)	124,606	-	1,987,324
81	941,625	-	(1,148)	37,250	-	977,727
83	1,394,943	24,127	(26,417)	44,743	-	1,437,396
84	824,777	186,983	(5,293)	472,494	-	1,478,961
86	3,831,668	36,854	(10,501)	245,907	-	4,103,928
87	288,843	-	(7)	(1,318)	-	287,518
88	1,202,993	-	(537)	2,440	-	1,204,897
89	338,068	(7,291)	(41)	142,723	-	473,459
140	1,761,022	402,532	(4,263)	(12,277)	-	2,147,014
160	597,609	-	-	-	-	597,609
161	1,191,547	-	-	-	-	1,191,547
162	656,676	153	-	-	-	656,828
163	7,014,953	280,740	(86,301)	20,887	-	7,230,280
164	2,260,152	74,761	(3,091)	22,194	-	2,354,016
165	823,928	-	(1,066)	-	-	822,862
166	1,079,361	87,589	(9,615)	45,821	-	1,203,155
167	1,064,346	41,998	(5,621)	24,085	-	1,124,808
169	502,024	-	(988)	-	-	501,035
197	283,772	5,226,600	(200,106)	4,057	-	5,314,323
200	701,572	63,952	-	202,649	-	968,173
201	1,505,440	-	(19)	-	-	1,505,421
202	334,387	-	(8,627)	(10,604)	-	315,157
203	986,561	39,268	(5,164)	-	-	1,020,665
204	975,467	0	(1,257)	(16,489)	-	957,721
205	388,523	-	-	-	-	388,523
207	1,798,053	-	-	-	-	1,798,053
208	635,822	-	(8)	-	-	635,814
209	867,179	-	(1,927)	3,621	-	868,872
210	1,600,773	259,572	(14,871)	(17,296)	-	1,828,178
211	9,656,856	(744,902)	(401,853)	11,704	-	8,521,805
212	1,647,880	-	-	8,233	-	1,656,113
213	2,214,526	-	-	142,487	-	2,357,014
214 (Note 1)	-	-	-	-	1,670,056	1,670,056
217	4,120,503	163,082	(635,029)	(94,668)	-	3,553,887
219	5,176,112	3,351,974	-	5,062	-	8,533,147
220	3,078,543	1,634,619	(91,011)	113	-	4,622,264
223	1,842,786	-	-	-	-	1,842,786
224	1,796,606	-	-	-	-	1,796,606
225	2,133,106	-	-	-	-	2,133,106
226	1,875,214	0	(4,868)	15,540	-	1,885,886
228	47,355	-	(8,184)	279	-	39,450
229	771,459	275,515	(13,487)	(8,626)	-	1,024,860
231	760,031	-	-	-	-	760,031
232	229,977	-	-	-	-	229,977
233	231,717	-	-	-	-	231,717
234	711,309	-	(33,755)	-	-	677,554
237	1,043,382	352,351	-	18,856	-	1,414,590
238	414,955	231,083	(9,256)	889	-	637,671
250	1,327,846	487,941	(33,685)	3,901	-	1,786,003
275 URD	1,548,200	-	-	-	-	1,548,200
277	1,954,403	-	-	-	-	1,954,403
Total 115kV Lines - LVPTF	$ 101,776,891	$ 12,528,115	$ (1,686,762)	$ 1,508,817	$ 1,670,056	$ 115,797,117
115kV Lines -Land						
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

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/09

	Investment	2009 Activity				Investment
	as of 12/31/08	Additions	Retires	Transfers	Adjustments	as of 12/31/09
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 (Note 1)	-	-	-	-	411,275	411,275
217	318,896		-	-	-	318,896
219	-	-	-	-	-	-
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	$ 4,627,250	$ -	$ -	$ -	$ 411,275	$ 5,038,525
345kV Lines(Including Land)						
374	$ 3,149,185	$ -	$ (62)	$ 6,599	$ -	$ 3,155,722
374 (Temp) Reassign to Substations	4,424,850	-	-	-	(4,424,850)	-
375	5,004,121	(49,539)	(5,518)	37,671	-	4,986,735
377	4,252,240	-	-	(33,363)	-	4,218,878
378	860,548	-	-	8,967	-	869,515
385	3,405,334	-	-	(36,864)	-	3,368,470
386	3,968,816	(316,960)	(339)	-	-	3,651,517
391	3,004,796	3,522	(465)	-	-	3,007,853
Total 345kV Lines - EHV	$ 28,069,890	$ (362,978)	$ (6,384)	$ (16,989)	$ (4,424,850)	$ 23,258,690
Total PTF Line	$ 134,474,031	$ 12,165,138	$ (1,693,146)	$ 1,491,828	$ (2,343,519)	$ 144,094,332
115kV Substations						
Augusta East	1,967,836	114,530	(32,593)	-	26,985	2,076,759
WF Wyman	880,154	83,206	-	-	-	963,360
Highland	688,823	234,328	(10,096)	-	25,231	938,286
Mason	2,663,140	759,870	(12,147)	-	9,444	3,420,307
Maxcy's 4,447,180		333,062	(3,851)	-	(2,806)	4,773,585
Bath	1,590,258	43,366	-	-	-	1,633,624
Puddledock	156,334	-	-	-	-	156,334
Bowman St	678,717	22,580	(8,288)	-	1,443	694,451
Newcastle	194,455	1,616,785	-	-	78,527	1,889,767
Crowley's	1,885,214	-	-	-	(116,538)	1,768,676
Gulf Island	2,848,910	25,997	(13,403)	667	(956)	2,861,215
Hotel Rd	534,831	(117)	-	-	(159)	534,555
Challenger Drive	153,976	-	-	-	-	153,976
Kimball Rd	4,461,322	281,218	(69,987)	-	122,593	4,795,146
Lewiston Lower	698,658	4,905	-	-	-	703,563
Livermore Falls	1,757,554	53,035	-	-	-	1,810,589
Norway 23,695		-	-	-	11	23,706
Surowiec 2,524,415		177,742	-	-	(829)	2,701,328
Norway Switch	45,083	-	-	-	-	45,083
Raymond	1,463,024	(2,465)	-	-	(1,428)	1,459,130
Rumford	579,168	1,211,278	(11,400)	-	59,992	1,839,039
Riley 511,749		-	-	-	(83)	511,666
Woodstock	111,915	5,390,087	-	-	56,243	5,558,245
Rumford IP	1,145,043	2,630	-	-	-	1,147,673
Louden	3,385,956	1,323,521	(12,055)	-	67,532	4,764,954
Moshers	2,113,186	79,500	(6,217)	-	(182)	2,186,287
Mussey	401,793	3,399	-	-	-	405,192
West Kennebunk	167,191	160,477	-	-	-	327,668
Pleasant Hill	940,878	36,170	(5,418)	-	(208)	971,422
Maguire Rd	17,945,169	(5,773,221)	(97,037)	-	(12,874)	12,062,037
Quaker Hill	1,037,720	249,920	(115,101)	-	8,344	1,180,884
Cape	659,435	(84,795)	-	-	-	574,641
Fore River	4,379,712	-	-	-	(4,659)	4,375,052
West Buxton	342,899	-	(2,443)	-	-	340,456
Sewall St	559,208	-	-	-	(1,054)	558,154
Spring St	1,947,098	17,672	-	-	5,170	1,969,939
Sanford	1,867,929	99,652	(50,024)	-	5,004	1,922,560
South Gorham	3,883,838	216,417	(19,315)	-	-	4,080,940
Red Brook	332,110	-	-	-	(203)	331,907
Westbrook 1,703,435		28,443	-	-	(7,590)	1,724,288
Lincolnville	304,453	668	-	-	-	305,121
Bucksport	2,309,190	48,787	-	-	-	2,357,977
Detroit	830,865	527,535	-	-	28,523	1,386,922
Sturtevant	142,527	-	-	-	-	142,527
Winslow	1,774,330	17,867	-	-	(8)	1,792,190
Wyman	1,853,699	153,131	(29,810)	-	7,527	1,984,546
Total 115kV	$ 80,894,077	$ 7,457,180	$ (499,187)	$ 667	$ 352,990	$ 88,205,726
345kV						
Mason	$ 1,406,573	$ (133,158)	$ -	$ -	$ -	$ 1,273,415
Maxcy's 4,844,378		(103,589)	(3,669)	-	-	4,737,120
Maine Yankee	4,127,348	81,672	-	-	-	4,209,020
Surowiec	4,617,925	(56,332)	-	-	-	4,561,593
Buxton	13,841,607	430,896	(1,743,054)	-	4,424,850	16,954,298
South Gorham	3,256,916	22,344,585	(16,589)	-	-	25,584,911
Total 345kV	$ 32,094,747	$ 22,564,073	$ (1,763,313)	$ -	$ 4,424,850	$ 57,320,357
Total Substations	$ 112,988,824	$ 30,021,253	$ (2,262,500)	$ 667	$ 4,777,840	$ 145,526,084
Total PTF	$ 247,462,855	$ 42,186,391	$ (3,955,646)	$ 1,492,495	$ 2,434,321	$ 289,620,416
SCADA & RTU Investment Directly Assigned to Schedule 1						(1,673,758)
Total PTF for Attachment F						$ 287,946,658

CENTRAL MAINE POWER COMPANY
POST 1996 RNS REVENUE REQUIREMENTS
FOR THE ADJUSTED TEST YEAR ENDED 12/31/09

Shading denotes an input

Line No.	FORECASTED TRANSMISSION REVENUE REQUIREMENTS (FTRR)	Forecast Period	Attachment F Reference Section:	Amount	Reference
1	Forecasted Rev Req'ts for FTPA			$ 4,247,743	line 6 below
2	Forecasted Rev Req'ts for FCWIP			29,479,474	line 9 below
3	Forecasted Transmission Revenue Requirements (Lines 1 + 2)			$ 33,727,217	
4	Forecasted Transmission Plant Additions (FTPA)	2010	Appendix C iv	$ 24,005,879	Worksheet 17
5	Carrying Charge Factor (CCF)		Appendix C vi	17.69%	line 14 below
6	Forecasted Rev Req'ts for FTPA (Lines 1*2)			$ 4,247,743	
7	Forcasted MPRP CWIP (FCWIP)		Appendix C v	$ 180,473,464	Worksheet 18
8	MPRP Cost of Capital Rate (MCOC)		Appendix C vii	16.33%	line 23 below
9	Forecasted Rev Req'ts for FCWIP (Lines 4*5)			$ 29,479,474	
	DERIVATION OF CARRYING CHARGE FACTOR (CCF)				
10	Investment Return and Income Taxes		(A)	$ 17,661,877	Worksheet 1, line 15
11	Depreciation Expense		(B)	4,508,795	Worksheet 1, line 16
12	Amortization of Loss on Reacquired Debt		(C)	77,953	Worksheet 1, line 17
13	Investment Tax Credit		(D)	(79,767)	Worksheet 1, line 18
14	Property Tax Expense		(E)	1,592,660	Worksheet 1, line 19
15	Payroll Tax Expense		(F)	-	Worksheet 1, line 20
16	Operation & Maintenance Expense		(G)	5,382,913	Worksheet 1, line 21
17	Administrative & General Expense		(H)	2,026,177	Worksheet 1, line 22
18	Total Expenses (Lines 10 thru 17)			$ 31,170,608	
19	PTF Transmission Plant		(A)(1)(a)	$ 176,158,940	Worksheet 1, line 1
20	Carrying Charge Factor (Lines 18/19)			17.69%	
	DERIVATION OF MPRP COST OF CAPITAL RATE (MCOC)				
21	Cost of Capital Rate - 11.64% ROE			14.98476%	Worksheet 2, line 33
22	Cost of Capital Rate - 1.25% bp ROE adder for MPRP			1.34976%	Worksheet 2, line 8
23	MPRP Cost of Capital Rate (MCOC) (Lines 21 + 22)			16.33452%	

Annual Report of Construction Costs
For FERC Informational Filings

MAINE POWER RELIABILITY PROGRAM
A CENTRAL MAINE POWER COMPANY PROGRAM

June 30, 2010 & July 30, 2010

Central Maine Power
IBERDROLA USA

Burns & McDonnell
SINCE 1898

TABLE OF CONTENTS

Page No.

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PART I – SUMMARY OF CONSTRUCTION COSTS FOR FERC INFORMATIONAL FILINGS

Summary of MPRP Costs for the June 30th and July 30st FERC Informational Filings

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

   In 2009, CMP did not include any CWIP in rates for MPRP. One component of the MPRP is the upgrade of the South Gorham substation. In April, 2008 CMP began the modifications to the substation, which included the addition of a second autotransformer. CMP did not include CWIP for South Gorham in rates in 2009. CMP accrued AFUDC on the South Gorham component of MPRP since CWIP was not included in rates and construction had begun. CMP ceased accruing AFUDC on South Gorham costs on May 31, 2010. In 2009, CMP placed approximately $22.4 million of costs associated with South Gorham in service. Additional work for components that have not been placed in service continues at South Gorham Substation and are included in CMP's projection of plant in service in 2010.

   Another MPRP project component is the Lewiston Loop. This component was not included in the Certificate of Public Convenience and Necessity (CPCN) for MPRP that was approved by the Maine Public Utilities Commission (MPUC) on June 10, 2010. Pursuant to the terms of a settlement stipulation, CMP is seeking a separate CPCN for the Lewiston Loop in a continuation of the MPUC proceeding. 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.

   Attachment 1 provides a summary of the monthly CWIP amounts for Lewiston Loop and South Gorham and shows the amounts that were transferred from CWIP to Plant in Service for South Gorham.

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

   CMP estimates the year end MPRP CWIP balance will be $180,473,464 for PTF facilities. CMP estimates the non-PTF balance to be $3,280,340 by the end of 2010. As discussed in Section 1, above, none of the costs associated with the Lewiston Loop component are included in the projected CWIP balance for MPRP.

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

   To date, CMP has not transferred any MPRP costs from CWIP in rates to Plant in Service. Attachment 1 provides a summary of the account transfers between CWIP and Plant in Service for the South Gorham CWIP account, which was not included in rates in 2009.

4. **A statement of the current status of the MPRP project and estimated in-service date(s) for the project.**

   CMP received its permit for construction of the MPRP from the Maine Department of Environmental Protection on April 5, 2010. On June 10, 2010 CMP received its Certificate of Public Convenience and Necessity (CPCN) for most of the MPRP components from the Maine Public Utilities Commission. CMP expects to receive the permit for construction of the MPRP from the Army Corps of Engineers in July 2010.

Below is a summary of the estimated in-service costs per year for MPRP by PTF and Non-PTF.

Year	PTF ($000)	Non-PTF ($000)
2009	$ 22,435	$ 0
2010	$ 4,600	$ 0
2011	$ 101,041	$ 2,364
2012	$ 399,337	$13,601
2013	$ 284,662	$ 2,509
2014	$ 559,781	$ 6,144
Total	$1,371,855	$24,618

Distribution costs are estimated at $8,449,000

Total project costs for currently permitted components are estimated to be $1,404,992,000

Deferred projects (not included above) are estimated at $99,697,000

Total: $1,504,689,000

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

Attachment 2 provides project cost summaries for the total project costs and costs by project element.

* * * * *

ATTACHEMENT 1 – SOUTH GORHAM AND LEWISTION LOOP CWIP AND PLANT IN SERVICE FOR 2009

Central Maine Power Company
FERC Informational Filing Attachment 1
South Gorham and Lewiston Loop CWIP and Plant in Service for 2009

	Pre 2009	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Total
South Gorham														
CWIP PTF	$ 1,994,416	(163,073)	1,288,383	906,058	879,666	2,070,664	5,190,196	(580,119)	3,593,835	1,460,969	(479,484)	222,777	403,778	$ 16,788,067
Transfer From CWIP to In Service PTF												(15,903,795)		$ (15,903,795)
In Service PTF	$ -	-	-	-	-	-	-	-	-	-	4,972,219.54	16,766,321	697,238	$ 22,435,778
														$ 23,320,049
Lewiston Loop														
CWIP PTF	$ 474,814	29,351	19,994	69,881	36,545	11,100	2,067	22,142	1,169	1,336	2,699	8,686	3,293	$ 683,076
CWIP Non PTF	$ 203,492	12,579	8,569	29,949	15,662	4,757	886	9,489	501	573	1,157	3,723	1,411	$ 292,747
In Service PTF	$ -	-	-	-	-	-	-	-	-	-	-	-	-	$ -
In Service Non PTF	$ -	-	-	-	-	-	-	-	-	-	-	-	-	$ -
														$ 975,824

Notes:
CMP did not include any MPRP-related CWIP in rates in 2009
Beginning June 1, 2010 CMP included projected year-end 2010 CWIP amounts for MPRP, including South Gorham, in rates
No Lewiston Loop CWIP costs have been included in CMP's rates.

ATTACHEMENT 2 – PROJECT COST SUMMARIES BY PROJECT ELEMENT

FIGURE 1 – MPRP USING THE REVISED SECTION 254 CONSTRUCTION (INCLUDES ALL SETTLMENT, DEFERRED, AND OMITTED PROJECTS)

PROJECT COST ESTIMATE & SCHEDULE SHEET

Transmission Owner:	**Central Maine Power**	**RSP Project #:**	**Various**
Project Name:	**Maine Power Reliability Program**	**Date:**	**6/28/2010**
Estimate Grade:	**D (Construction)**		

1. Project Scope Summary

Central Maine Power plans to invest $1.5 billion to modernize our 40-year-old bulk power system. The proposed improvements are designed to keep the system operating reliably over the coming decades and to provide the infrastructure for the state's emerging wind, hydro, biomass, and tidal energy industries. The Maine Power Reliability Program will add to the company's network of substations and transmission lines that stretch from the Town of Eliot on the New Hampshire border to Orrington, where it connects to transmission lines from northern and eastern Maine. Central Maine Power filed for approval by the Maine Public Utilities Commission in July 2008. The project will also require approvals from the Maine Department of Environmental Protection and approximately 80 local governments and other agencies. The company expects to begin construction in 2010 for completion in 2015.

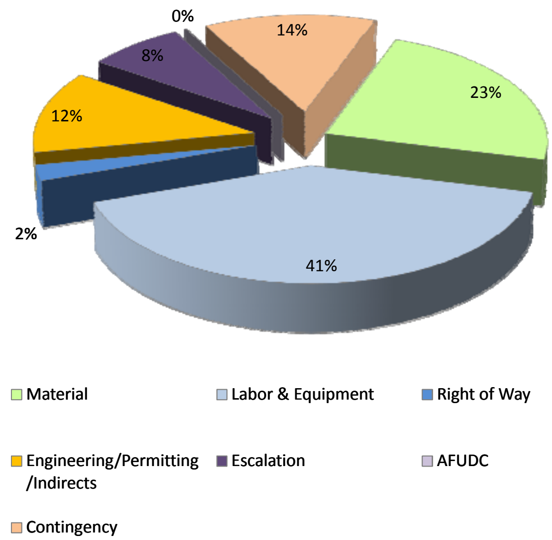
2. Project Cost Summary

Prior Estimated Cost:

2.1. Project Cost Summary

	PTF	Non-PTF*	Total
Material	$ 341,763,529	$ 8,256,471	$ 350,020,000
Labor & Equipment	$ 601,021,292	$ 14,519,708	$ 615,541,000
Right of Way	$ 34,910,614	$ 843,386	$ 35,754,000
Engineering/Permitting /Indirects	$ 182,805,680	$ 4,421,253	$ 187,226,933
Escalation	$ 110,518,057	$ 2,669,943	$ 113,188,000
AFUDC	$ 205,067	$ -	$ 205,067
Contingency	$ 197,963,964	$ 4,790,036	$ 202,754,000
Total Project Cost	$ 1,469,188,203	$ 35,500,797	**$ 1,504,689,000**

*Distribution costs carried in Non-PTF are estimated at $8,449,000



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	$ 91,138,371	$ 245,072,750	$ 17,107,000	$ 67,339,753	$ 40,710,233	$ -	$ 72,924,360	**$ 534,292,467**
2.2.2 New 115KV Lines	$ 25,823,361	$ 93,723,280	$ 8,001,000	$ 22,573,033	$ 13,646,522	$ -	$ 24,445,056	**$ 188,212,252**
2.2.3 New 345KV Substations	$ 129,103,217	$ 74,437,833	$ 9,764,000	$ 39,884,003	$ 24,111,865	$ -	$ 43,191,655	**$ 320,492,573**
2.2.4 New 115KV Substations	$ 7,722,359	$ 5,750,169	$ 294,000	$ 2,574,080	$ 1,556,159	$ -	$ 2,787,553	**$ 20,684,320**
2.2.5 345 KV Substations Expansions/Modifications	$ 37,558,955	$ 16,637,259	$ 294,000	$ 10,188,638	$ 6,159,539	$ 134,057	$ 11,033,600	**$ 82,006,048**
2.2.6 115 KV Substations Expansions/Modifications	$ 15,110,909	$ 7,859,302	$ 294,000	$ 4,349,967	$ 2,629,771	$ 71,010	$ 4,710,717	**$ 35,025,676**
2.2.7 Lines Rerates, Relocations, Rebuilds	$ 43,562,828	$ 172,060,406	$ -	$ 40,317,459	$ 24,373,911	$ -	$ 43,661,059	**$ 323,975,664**
Total	**$ 350,020,000**	**$ 615,541,000**	**$ 35,754,000**	**$ 187,226,933**	**$ 113,188,000**	**$ 205,067**	**$ 202,754,000**	**$ 1,504,689,000**

Note: Values expressed in 2008 dollars.

2010 COST ESTIMATE & SCHEDULE SHEET

Transmission Owner:	**Central Maine Power**	**RSP Project #:**	**Various**
Project Name:	**Maine Power Reliability Program**	**Date:**	**6/28/2010**
Estimate Grade:	**D (Construction)**		

1. Project Scope Summary

Central Maine Power plans to invest $1.5 billion to modernize our 40-year-old bulk power system. The proposed improvements are designed to keep the system operating reliably over the coming decades and to provide the infrastructure for the state's emerging wind, hydro, biomass, and tidal energy industries. The Maine Power Reliability Program will add to the company's network of substations and transmission lines that stretch from the Town of Eliot on the New Hampshire border to Orrington, where it connects to transmission lines from northern and eastern Maine. Central Maine Power filed for approval by the Maine Public Utilities Commission in July 2008. The project will also require approvals from the Maine Department of Environmental Protection and approximately 80 local governments and other agencies. The company expects to begin construction in 2010 for completion in 2015.

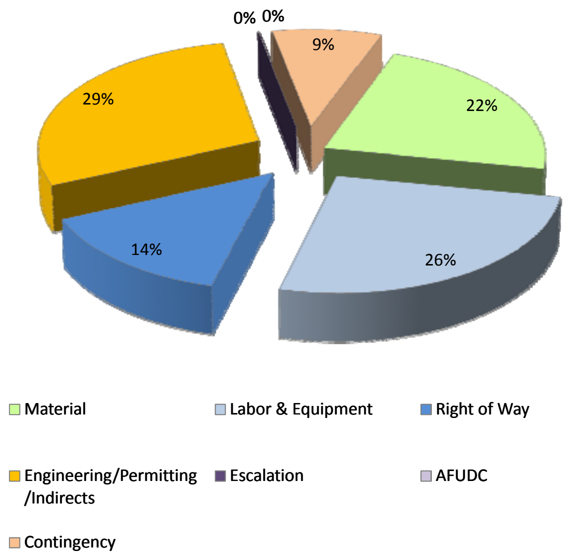
2. 2010 Project Cost Summary

Prior Estimated Cost:

2.1. 2010 Project Cost Summary

	PTF	Non-PTF*	**Total**
Material	$ 27,220,686	$ 513,113	$ 27,733,799
Labor & Equipment	$ 30,968,600	$ 957,792	$ 31,926,391
Right of Way	$ 16,849,579	$ 722,974	$ 17,572,553
Engineering/Permitting /Indirects	$ 35,042,397	$ 364,213	$ 35,406,610
Escalation	$ -	$ -	$ -
AFUDC	$ 8,016	$ -	$ 8,016
Contingency	$ 10,340,439	$ 243,429	$ 10,583,868
Total Project Cost	$ 120,429,717	$ 2,801,521	**$ 123,231,237**

*2010 Distribution costs carried in Non-PTF are estimated at $669,054



2.2 Detailed 2010 Cost Summary By Project Element

	Material	Labor & Equip.	Right of Way	Indirects	Escalation	AFUDC	Contingency	**Total**
2.2.1 New 345KV Lines	$ 6,871,892	$ 461,741	$ 11,161,726	$ 9,235,216	$ -	$ -	$ 3,806,691	**$ 31,537,266**
2.2.2 New 115KV Lines	$ 3,447,205	$ 2,976,004	$ 578,478	$ 3,517,195	$ -	$ -	$ 1,276,045	**$ 11,794,927**
2.2.3 New 345KV Substations	$ 4,310,954	$ 13,463,105	$ 4,798,859	$ 10,886,750	$ -	$ -	$ 1,254,628	**$ 34,714,295**
2.2.4 New 115KV Substations	$ -	$ 866,094	$ 644,497	$ 473,282	$ -	$ -	$ 145,512	**$ 2,129,384**
2.2.5 345 KV Substations Expansions/Modifications	$ 2,330,167	$ 3,245,267	$ 144,497	$ 2,534,478	$ -	$ 8,016	$ 575,960	**$ 8,838,385**
2.2.6 115 KV Substations Expansions/Modifications	$ 1,922,992	$ 2,620,821	$ 144,497	$ 2,411,423	$ -	$ -	$ 245,902	**$ 7,345,634**
2.2.7 Lines Rerates, Relocations, Rebuilds	$ 8,850,590	$ 8,293,360	$ -	$ 6,348,265	$ -	$ -	$ 3,279,131	**$ 26,771,345**
Total	**$ 27,733,799**	**$ 31,926,391**	**$ 17,472,553**	**$ 35,406,610**	**$ -**	**$ 8,016**	**$ 10,583,868**	**$ 123,131,237**

Note: Values expressed in 2008 dollars.

2011 COST ESTIMATE & SCHEDULE SHEET

Transmission Owner:	**Central Maine Power**	**RSP Project #:**	**Various**
Project Name:	**Maine Power Reliability Program**	**Date:**	**6/28/2010**
Estimate Grade:	**D (Construction)**		

1. Project Scope Summary

Central Maine Power plans to invest $1.5 billion to modernize our 40-year-old bulk power system. The proposed improvements are designed to keep the system operating reliably over the coming decades and to provide the infrastructure for the state's emerging wind, hydro, biomass, and tidal energy industries. The Maine Power Reliability Program will add to the company's network of substations and transmission lines that stretch from the Town of Eliot on the New Hampshire border to Orrington, where it connects to transmission lines from northern and eastern Maine. Central Maine Power filed for approval by the Maine Public Utilities Commission in July 2008. The project will also require approvals from the Maine Department of Environmental Protection and approximately 80 local governments and other agencies. The company expects to begin construction in 2010 for completion in 2015.

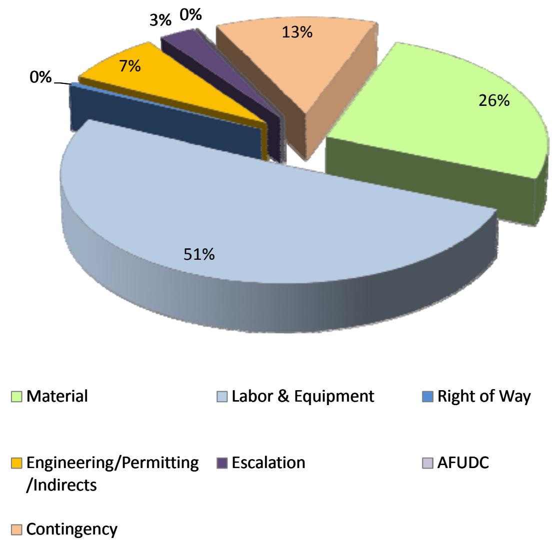
2. 2011 Project Cost Summary

Prior Estimated Cost:

2.1. 2011 Project Cost Summary

	PTF	Non-PTF*	**Total**
Material	$ 82,967,907	$ 2,004,375	$ 84,972,282
Labor & Equipment	$ 163,790,286	$ 3,956,917	$ 167,747,203
Right of Way	$ 1,640,021	$ 39,620	$ 1,679,641
Engineering/Permitting /Indirects	$ 24,330,450	$ 587,786	$ 24,918,236
Escalation	$ 8,790,047	$ 212,354	$ 9,002,401
AFUDC	$ -	$ -	$ -
Contingency	$ 40,936,699	$ 988,966	$ 41,925,665
Total Project Cost	$ 322,455,411	$ 7,790,017	**$ 330,245,428**

*Distribution costs carried in Non-PTF are estimated at $1,995,225



2.2 2011 Detailed Cost Summary By Project Element

	Material	Labor & Equip.	Right of Way	Indirects	Escalation	AFUDC	Contingency	**Total**
2.2.1 New 345KV Lines	$ 24,058,024	$ 59,954,749	$ 757,657	$ 9,534,915	$ 5,622,196	$ -	$ 16,677,716	**$ 116,605,257**
2.2.2 New 115KV Lines	$ 8,130,968	$ 29,509,967	$ 219,000	$ 5,248,966	$ 1,173,779	$ -	$ 8,697,846	**$ 52,980,526**
2.2.3 New 345KV Substations	$ 32,002,002	$ 11,274,025	$ 254,473	$ 4,775,228	$ 1,163,905	$ -	$ 1,351,932	**$ 50,821,566**
2.2.4 New 115KV Substations	$ 7,373,256	$ 4,589,249	$ 149,503	$ 1,921,967	$ 513,725	$ -	$ 2,392,501	**$ 16,940,201**
2.2.5 345 KV Substations Expansions/Modifications	$ 2,566,125	$ 1,672,304	$ 149,503	$ 242,432	$ 87,585	$ -	$ 407,899	**$ 5,125,848**
2.2.6 115 KV Substations Expansions/Modifications	$ 2,293,545	$ 4,058,811	$ 149,504	$ 1,070,536	$ 206,122	$ -	$ 959,944	**$ 8,738,461**
2.2.7 Lines Rerates, Relocations, Rebuilds	$ 8,548,362	$ 56,688,098	$ -	$ 2,124,192	$ 235,089	$ -	$ 11,437,828	**$ 79,033,568**
Total	**$ 84,972,282**	**$ 167,747,203**	**$ 1,679,641**	**$ 24,918,236**	**$ 9,002,401**	**$ -**	**$ 41,925,665**	**$ 330,245,428**

Note: Values expressed in 2008 dollars.

2012 COST ESTIMATE & SCHEDULE SHEET

Transmission Owner:	**Central Maine Power**	**RSP Project #:**	**Various**
Project Name:	**Maine Power Reliability Program**	**Date:**	**6/28/2010**
Estimate Grade:	**D (Construction)**		

1. Project Scope Summary

Central Maine Power plans to invest $1.5 billion to modernize our 40-year-old bulk power system. The proposed improvements are designed to keep the system operating reliably over the coming decades and to provide the infrastructure for the state's emerging wind, hydro, biomass, and tidal energy industries. The Maine Power Reliability Program will add to the company's network of substations and transmission lines that stretch from the Town of Eliot on the New Hampshire border to Orrington, where it connects to transmission lines from northern and eastern Maine. Central Maine Power filed for approval by the Maine Public Utilities Commission in July 2008. The project will also require approvals from the Maine Department of Environmental Protection and approximately 80 local governments and other agencies. The company expects to begin construction in 2010 for completion in 2015.

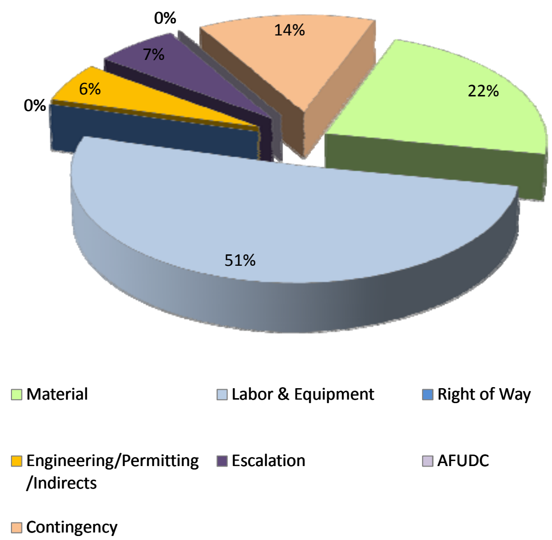
2. 2012 Project Cost Summary

Prior Estimated Cost:

2.1. 2012 Project Cost Summary

	PTF	Non-PTF*	**Total**
Material	$ 95,322,451	$ 2,302,841	$ 97,625,292
Labor & Equipment	$ 217,555,376	$ 5,255,797	$ 222,811,173
Right of Way	$ -	$ -	$ -
Engineering/Permitting /Indirects	$ 24,947,490	$ 602,692	$ 25,550,182
Escalation	$ 27,573,198	$ 666,125	$ 28,239,323
AFUDC	$ -	$ -	$ -
Contingency	$ 59,135,936	$ 1,428,632	$ 60,564,568
Total Project Cost	$ 424,534,452	$ 10,256,087	**$ 434,790,538**

*Distribution costs carried in Non-PTF are estimated at $2,626,849



2.2 2012 Detailed Cost Summary By Project Element

	Material	Labor & Equip.	Right of Way	Indirects	Escalation	AFUDC	Contingency	**Total**
2.2.1 New 345KV Lines	$ 32,802,716	$ 112,718,066	$ -	$ 10,025,802	$ 12,186,262	$ -	$ 33,135,742	**$ 200,868,588**
2.2.2 New 115KV Lines	$ 6,236,219	$ 37,225,215	$ -	$ 2,549,053	$ 5,817,339	$ -	$ 6,042,317	**$ 57,870,143**
2.2.3 New 345KV Substations	$ 33,274,705	$ 19,646,053	$ -	$ 5,595,372	$ 3,184,282	$ -	$ 12,263,361	**$ 73,963,773**
2.2.4 New 115KV Substations	$ 2,412,198	$ 536,182	$ -	$ 101,883	$ 612,606	$ -	$ 241,505	**$ 3,904,374**
2.2.5 345 KV Substations Expansions/Modifications	$ 13,750,502	$ 6,043,982	$ -	$ 2,072,384	$ 2,290,501	$ -	$ 2,912,413	**$ 27,069,782**
2.2.6 115 KV Substations Expansions/Modifications	$ 7,561,039	$ 9,633,710	$ -	$ 1,599,797	$ 662,926	$ -	$ 1,421,769	**$ 20,879,241**
2.2.7 Lines Rerates, Relocations, Rebuilds	$ 1,587,914	$ 37,007,966	$ -	$ 3,605,890	$ 3,485,408	$ -	$ 4,547,460	**$ 50,234,637**
Total	**$ 97,625,292**	**$ 222,811,173**	**$ -**	**$ 25,550,182**	**$ 28,239,323**	**$ -**	**$ 60,564,568**	**$ 434,790,538**

Note: Values expressed in 2008 dollars.

2013 COST ESTIMATE & SCHEDULE SHEET

Transmission Owner:	**Central Maine Power**	**RSP Project #:**	**Various**
Project Name:	**Maine Power Reliability Program**	**Date:**	**6/28/2010**
Estimate Grade:	**D (Construction)**		

1. Project Scope Summary

Central Maine Power plans to invest $1.5 billion to modernize our 40-year-old bulk power system. The proposed improvements are designed to keep the system operating reliably over the coming decades and to provide the infrastructure for the state's emerging wind, hydro, biomass, and tidal energy industries. The Maine Power Reliability Program will add to the company's network of substations and transmission lines that stretch from the Town of Eliot on the New Hampshire border to Orrington, where it connects to transmission lines from northern and eastern Maine. Central Maine Power filed for approval by the Maine Public Utilities Commission in July 2008. The project will also require approvals from the Maine Department of Environmental Protection and approximately 80 local governments and other agencies. The company expects to begin construction in 2010 for completion in 2015.

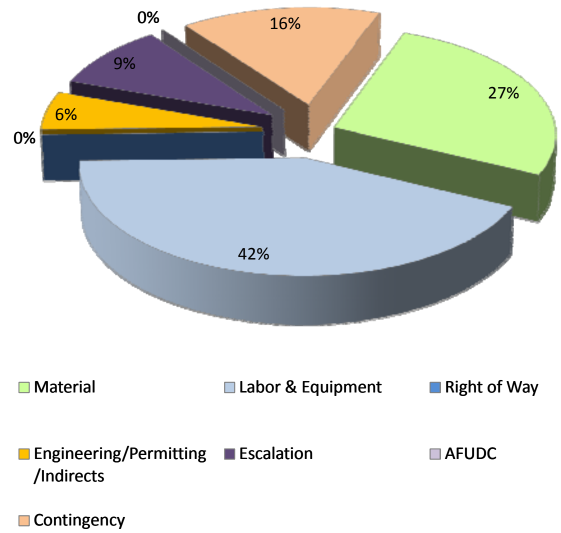
2. 2013 Project Cost Summary

Prior Estimated Cost:

2.1. 2013 Project Cost Summary

	PTF	Non-PTF*	Total
Material	$ 90,047,092	$ 2,175,397	$ 92,222,489
Labor & Equipment	$ 144,325,104	$ 3,486,668	$ 147,811,772
Right of Way	$ -	$ -	$ -
Engineering/Permitting /Indirects	$ 19,526,323	$ 471,725	$ 19,998,048
Escalation	$ 32,344,577	$ 781,394	$ 33,125,971
AFUDC	$ -	$ -	$ -
Contingency	$ 53,165,060	$ 1,284,385	$ 54,449,445
Total Project Cost	$ 339,408,156	$ 8,199,569	**$ 347,607,725**

*Distribution costs carried in Non-PTF are estimated at $2,100,122



2.2 2013 Detailed Cost Summary By Project Element

	Material	Labor & Equip.	Right of Way	Indirects	Escalation	AFUDC	Contingency	Total
2.2.1 New 345KV Lines	$ 26,837,957	$ 54,606,831	$ -	$ 5,009,718	$ 11,611,319	$ -	$ 19,085,626	**$ 117,151,451**
2.2.2 New 115KV Lines	$ 7,603,389	$ 28,668,582	$ -	$ 2,865,195	$ 4,746,082	$ -	$ 7,801,176	**$ 51,684,424**
2.2.3 New 345KV Substations	$ 35,892,445	$ 27,719,427	$ -	$ 5,901,991	$ 9,776,414	$ -	$ 15,069,575	**$ 94,359,853**
2.2.4 New 115KV Substations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
2.2.5 345 KV Substations Expansions/Modifications	$ 15,115,591	$ 6,974,506	$ -	$ 2,144,503	$ 3,552,284	$ -	$ 4,838,920	**$ 32,625,805**
2.2.6 115 KV Substations Expansions/Modifications	$ 3,259,738	$ 2,770,944	$ -	$ 473,229	$ 783,885	$ -	$ 1,288,479	**$ 8,576,275**
2.2.7 Lines Rerates, Relocations, Rebuilds	$ 3,513,369	$ 27,071,482	$ -	$ 3,603,411	$ 2,655,987	$ -	$ 6,365,668	**$ 43,209,918**
Total	**$ 92,222,489**	**$ 147,811,772**	**$ -**	**$ 19,998,048**	**$ 33,125,971**	**$ -**	**$ 54,449,445**	**$ 347,607,725**

Note: Values expressed in 2008 dollars.

2014 COST ESTIMATE & SCHEDULE SHEET

Transmission Owner:	**Central Maine Power**	**RSP Project #:**	**Various**
Project Name:	**Maine Power Reliability Program**	**Date:**	**6/28/2010**
Estimate Grade:	**D (Construction)**		

1. Project Scope Summary

Central Maine Power plans to invest $1.5 billion to modernize our 40-year-old bulk power system. The proposed improvements are designed to keep the system operating reliably over the coming decades and to provide the infrastructure for the state's emerging wind, hydro, biomass, and tidal energy industries. The Maine Power Reliability Program will add to the company's network of substations and transmission lines that stretch from the Town of Eliot on the New Hampshire border to Orrington, where it connects to transmission lines from northern and eastern Maine. Central Maine Power filed for approval by the Maine Public Utilities Commission in July 2008. The project will also require approvals from the Maine Department of Environmental Protection and approximately 80 local governments and other agencies. The company expects to begin construction in 2010 for completion in 2015.

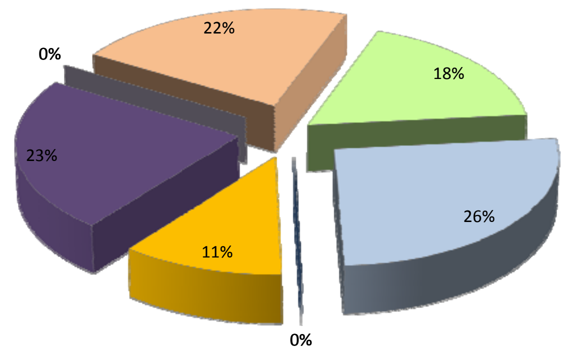
2. 2014 Project Cost Summary

Prior Estimated Cost:

2.1. 2014 Project Cost Summary

	PTF	Non-PTF*	Total
Material	$ 27,650,448	$ 667,991	$ 28,318,439
Labor & Equipment	$ 40,389,572	$ 975,749	$ 41,365,321
Right of Way	$ -	$ -	$ -
Engineering/Permitting /Indirects	$ 16,999,677	$ 410,686	$ 17,410,363
Escalation	$ 35,746,683	$ 863,584	$ 36,610,267
AFUDC	$ -	$ -	$ -
Contingency	$ 33,979,415	$ 820,889	$ 34,800,305
Total Project Cost	$ 154,765,796	$ 3,738,899	**$ 158,504,695**

*Distribution costs carried in Non-PTF are estimated at $957,628



2.2 2014 Detailed Cost Summary By Project Element

	Material	Labor & Equip.	Right of Way	Indirects	Escalation	AFUDC	Contingency	Total
2.2.1 New 345KV Lines	$ -	$ -	$ -	$ -	$ -		$ -	**$ -**
2.2.2 New 115KV Lines	$ -	$ -	$ -	$ -	$ -		$ -	**$ -**
2.2.3 New 345KV Substations	$ 20,049,632	$ 4,456,453	$ -	$ 7,101,167	$ 14,932,235		$ 14,194,005	**$ 60,733,493**
2.2.4 New 115KV Substations	$ -	$ -	$ -	$ -	$ -		$ -	**$ -**
2.2.5 345 KV Substations Expansions/Modifications	$ 1,471,077	$ 244,434	$ -	$ 2,503,654	$ 1,059,077		$ 1,006,718	**$ 6,284,960**
2.2.6 115 KV Substations Expansions/Modifications	$ 999,677	$ 1,268,803	$ -	$ 2,784,765	$ 1,150,194		$ 1,568,610	**$ 7,772,049**
2.2.7 Lines Rerates, Relocations, Rebuilds	$ 5,798,054	$ 35,395,630	$ -	$ 5,020,776	$ 19,468,762		$ 18,030,971	**$ 83,714,193**
Total	**$ 28,318,439**	**$ 41,365,321**	**$ -**	**$ 17,410,363**	**$ 36,610,267**	**$ -**	**$ 34,800,305**	**$ 158,504,695**

Note: Values expressed in 2008 dollars.

2015 COST ESTIMATE & SCHEDULE SHEET

Transmission Owner:	**Central Maine Power**	**RSP Project #:**	**Various**
Project Name:	**Maine Power Reliability Program**	**Date:**	**6/28/2010**
Estimate Grade:	**D (Construction)**		

1. Project Scope Summary

Central Maine Power plans to invest $1.5 billion to modernize our 40-year-old bulk power system. The proposed improvements are designed to keep the system operating reliably over the coming decades and to provide the infrastructure for the state's emerging wind, hydro, biomass, and tidal energy industries. The Maine Power Reliability Program will add to the company's network of substations and transmission lines that stretch from the Town of Eliot on the New Hampshire border to Orrington, where it connects to transmission lines from northern and eastern Maine. Central Maine Power filed for approval by the Maine Public Utilities Commission in July 2008. The project will also require approvals from the Maine Department of Environmental Protection and approximately 80 local governments and other agencies. The company expects to begin construction in 2010 for completion in 2015.

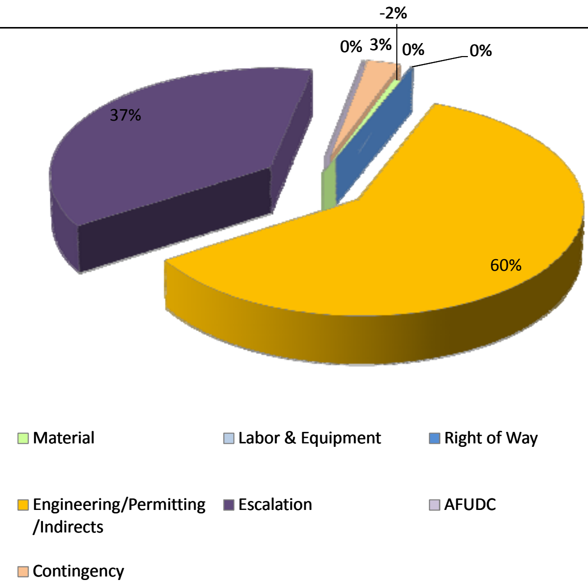
2. 2015 Project Cost Summary

Prior Estimated Cost:

2.1. 2015 Project Cost Summary

	PTF	Non-PTF*	**Total**
Material	$ (94,419)	$ -	$ (94,419)
Labor & Equipment	$ -	$ -	$ -
Right of Way	$ -	$ -	$ -
Engineering/Permitting /Indirects	$ 9,789,729	$ 236,505	$ 10,026,234
Escalation	$ 6,063,551	$ 146,486	$ 6,210,037
AFUDC	$ -	$ -	$ -
Contingency	$ 420,003	$ 10,147	$ 430,150
Total Project Cost	$ 16,178,865	$ 393,137	**$ 16,572,002**

*Distribution costs carried in Non-PTF are estimated at $100,122



2.2 2015 Detailed Cost Summary By Project Element

	Material	Labor & Equip.	Right of Way	Indirects	Escalation	AFUDC	Contingency	**Total**
2.2.1 New 345KV Lines	$ -	$ -	$ -	$ 1,780,083	$ 1,102,545		$ 76,370	**$ 2,958,998**
2.2.2 New 115KV Lines	$ (94,419)	$ -	$ -	$ 5,640,177	$ 3,493,406		$ 241,977	**$ 9,281,141**
2.2.3 New 345KV Substations	$ -	$ -	$ -	$ 1,067,773	$ 661,356		$ 45,810	**$ 1,774,940**
2.2.4 New 115KV Substations	$ -	$ -	$ -	$ 68,913	$ 42,683		$ 2,957	**$ 114,553**
2.2.5 345 KV Substations Expansions/Modifications	$ -	$ -	$ -	$ 273,217	$ 169,225		$ 11,722	**$ 454,163**
2.2.6 115 KV Substations Expansions/Modifications	$ -	$ -	$ -	$ 116,694	$ 72,278		$ 5,006	**$ 193,978**
2.2.7 Lines Rerates, Relocations, Rebuilds	$ -	$ -	$ -	$ 1,079,378	$ 668,544		$ 46,308	**$ 1,794,230**
Total	**$ (94,419)**	**$ -**	**$ -**	**$ 10,026,234**	**$ 6,210,037**	**$ -**	**$ 430,150**	**$ 16,572,002**

Note: Values expressed in 2008 dollars.

FIGURE 2 – MPRP SETTLEMENT PROJECTS

SETTLMENT PACKAGE PROJECT COST ESTIMATE & SCHEDULE SHEET

Transmission Owner:	**Central Maine Power**	**RSP Project #:**	**Various**
Project Name:	**Maine Power Reliability Program Settlement Package**	**Date:**	**6/28/2010**
Estimate Grade:	**D (Construction)**		

1. Settlement Package Project Scope Summary

Central Maine Power plans to invest $1.4 billion to modernize our 40-year-old bulk power system. The proposed improvements are designed to keep the system operating reliably over the coming decades and to provide the infrastructure for the state's emerging wind, hydro, biomass, and tidal energy industries. The Maine Power Reliability Program will add to the company's network of substations and transmission lines that stretch from the Town of Eliot on the New Hampshire border to Orrington, where it connects to transmission lines from northern and eastern Maine. Central Maine Power filed for approval by the Maine Public Utilities Commission in July 2008. The project will also require approvals from the Maine Department of Environmental Protection and approximately 80 local governments and other agencies. The company expects to begin construction in 2010 for completion in 2015.

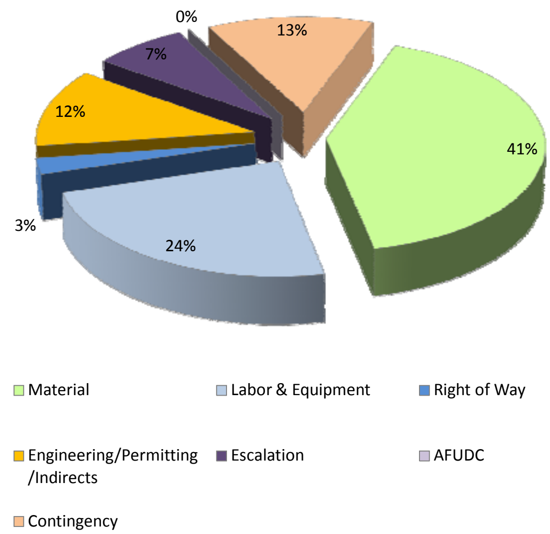
2. Settlement Package Project Cost Summary

Prior Estimated Cost:

2.1. Settlement Package Project Cost Summary

	PTF	Non-PTF*	**Total**
Material	$ 565,311,613	$ 13,657,042	$ 578,968,655
Labor & Equipment	$ 323,676,396	$ 7,819,514	$ 331,495,910
Right of Way	$ 34,027,851	$ 822,060	$ 34,849,911
Engineering/Permitting /Indirects	$ 165,333,274	$ 3,994,193	$ 169,327,467
Escalation	$ 101,789,996	$ 2,459,087	$ 104,249,083
AFUDC	$ 130,895	$ 3,162	$ 134,057
Contingency	$ 181,511,875	$ 4,385,042	$ 185,896,917
Total Project Cost	$ 1,371,781,900	$ 33,140,100	**$ 1,404,922,000**

*Distribution costs carried in Non-PTF are estimated at $7,887,167



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	$ 154,613,957	$ 132,636,837	$ 11,625,350	$ 56,484,824	$ 34,775,759	$ -	$ 62,012,117	**$ 452,148,844**
2.2.2 New 115KV Lines	$ 37,276,478	$ 48,839,376	$ 3,689,116	$ 17,924,543	$ 11,035,523	$ -	$ 19,678,539	**$ 138,443,576**
2.2.3 New 345KV Substations	$ 219,020,364	$ 40,286,807	$ 8,709,417	$ 42,316,993	$ 26,053,114	$ -	$ 46,457,900	**$ 382,844,594**
2.2.4 New 115KV Substations	$ 6,668,135	$ 1,473,574	$ 278,146	$ 1,351,444	$ 832,037	$ -	$ 1,483,689	**$ 12,087,025**
2.2.5 345 KV Substations Expansions/Modifications	$ 63,717,824	$ 9,418,941	$ 2,412,789	$ 11,723,172	$ 7,217,553	$ 87,637	$ 12,870,337	**$ 107,448,252**
2.2.6 115 KV Substations Expansions/Modifications	$ 23,768,655	$ 4,281,967	$ 940,434	$ 4,569,348	$ 2,813,190	$ 46,421	$ 5,016,479	**$ 41,436,493**
2.2.7 Lines Rerates, Relocations, Rebuilds	$ 73,903,243	$ 94,558,408	$ 7,194,659	$ 34,957,143	$ 21,521,908	$ -	$ 38,377,856	**$ 270,513,217**
Total	**$ 578,968,655**	**$ 331,495,910**	**$ 34,849,911**	**$ 169,327,467**	**$ 104,249,083**	**$ 134,057**	**$ 185,896,917**	**$ 1,404,922,000**

Note: Values expressed in 2008 dollars.

2010 SETTLMENT PACKAGE PROJECT COST ESTIMATE & SCHEDULE SHEET

Transmission Owner:	**Central Maine Power**	**RSP Project #:**	**Various**
Project Name:	**Maine Power Reliability Program Settlement Package**	**Date:**	**6/28/2010**
Estimate Grade:	**D (Construction)**		

1. 2010 Settlement Package Project Scope Summary

Central Maine Power plans to invest $1.5 billion to modernize our 40-year-old bulk power system. The proposed improvements are designed to keep the system operating reliably over the coming decades and to provide the infrastructure for the state's emerging wind, hydro, biomass, and tidal energy industries. The Maine Power Reliability Program will add to the company's network of substations and transmission lines that stretch from the Town of Eliot on the New Hampshire border to Orrington, where it connects to transmission lines from northern and eastern Maine. Central Maine Power filed for approval by the Maine Public Utilities Commission in July 2008. The project will also require approvals from the Maine Department of Environmental Protection and approximately 80 local governments and other agencies. The company expects to begin construction in 2010 for completion in 2015.

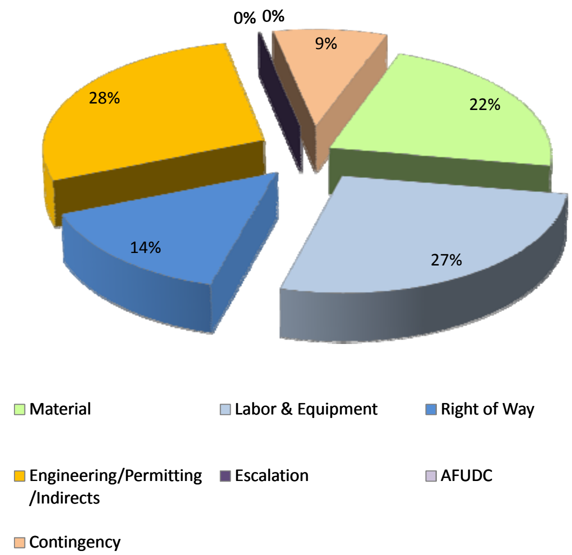
2. 2010 Settlement Package Project Cost Summary

Prior Estimated Cost:

2.1. 2010 Settlement Package Project Cost Summary

	PTF	Non-PTF*	**Total**
Material	$ 25,869,773	$ 487,648	$ 26,357,421
Labor & Equipment	$ 30,900,365	$ 955,681	$ 31,856,046
Right of Way	$ 16,777,878	$ 719,898	$ 17,497,776
Engineering/Permitting /Indirects	$ 32,832,503	$ 341,244	$ 33,173,747
Escalation	$ -	$ -	$ -
AFUDC	$ 5,062	$ -	$ 5,062
Contingency	$ 10,340,439	$ 243,429	$ 10,583,868
Total Project Cost	$ 116,726,020	$ 2,747,901	**$ 119,473,920**

*2010 Distribution costs carried in Non-PTF are estimated at $669,054



2.2 Detailed 2010 Cost Summary By Project Element

	Material	Labor & Equip.	Right of Way	Indirects	Escalation	AFUDC	Contingency	**Total**
2.2.1 New 345KV Lines	$ 6,530,852	$ 460,723	$ 11,711,676	$ 8,652,812	$ -	$ -	$ 3,806,691	**$ 31,162,755**
2.2.2 New 115KV Lines	$ 3,751,313	$ 2,969,447	$ 576,016	$ 3,295,389	$ -	$ -	$ 1,276,045	**$ 11,868,210**
2.2.3 New 345KV Substations	$ 4,572,195	$ 14,930,136	$ 4,778,438	$ 10,200,195	$ -	$ -	$ 2,254,628	**$ 36,735,591**
2.2.4 New 115KV Substations	$ -	$ 864,185	$ 143,882	$ 443,435	$ -	$ -	$ 145,512	**$ 1,597,014**
2.2.5 345 KV Substations Expansions/Modifications	$ 2,214,525	$ 3,238,117	$ 143,882	$ 2,374,645	$ -	$ 5,062	$ 575,960	**$ 8,552,190**
2.2.6 115 KV Substations Expansions/Modifications	$ 877,185	$ 4,610,640	$ 143,882	$ 2,259,350	$ -	$ -	$ 245,902	**$ 8,136,959**
2.2.7 Lines Rerates, Relocations, Rebuilds	$ 8,411,351	$ 4,782,798	$ -	$ 5,947,922	$ -	$ -	$ 2,279,131	**$ 21,421,202**
Total	**$ 26,357,421**	**$ 31,856,046**	**$ 17,497,776**	**$ 33,173,748**	**$ -**	**$ 5,062**	**$ 10,583,868**	**$ 119,473,921**

Note: Values expressed in 2008 dollars.

FIGURE 3 – MPRP DEFERRED AND OMITTED PROJECTS

DEFERRED & OMITTED PROJECTS COST ESTIMATE & SCHEDULE SHEET

Transmission Owner:	**Central Maine Power**	**RSP Project #:**	**Various**
Project Name:	**Maine Power Reliability Program Deferred / Omitted**	**Date:**	**6/28/2010**
Estimate Grade:	**D (Construction)**		

1. Deferred & Omitted Project Scope Summary

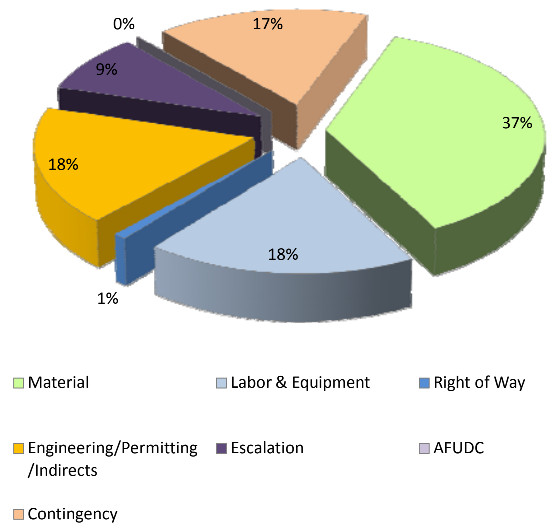
Central Maine Power plans to seek approval of $100 million in projects that were deferred or omitted from the overall MPRP $1.5 billion modernization of Central Maine Power's 40-year-old bulk power system. The proposed improvements are designed to keep the system operating reliably over the coming decades and to provide the infrastructure for the state's emerging wind, hydro, biomass, and tidal energy industries.

2. Deferred & Omitted Project Cost Summary

Prior Estimated Cost:

2.1. Deferred & Omitted Project Cost Summary

	PTF	Non-PTF	**Total**
Material	$ 35,709,656	$ 862,689	$ 36,572,345
Labor & Equipment	$ 18,087,133	$ 436,957	$ 18,524,090
Right of Way	$ 882,763	$ 21,326	$ 904,089
Engineering/Permitting /Indirects	$ 17,477,243	$ 422,223	$ 17,899,466
Escalation	$ 8,728,061	$ 210,856	$ 8,938,917
AFUDC	$ 69,335	$ 1,675	$ 71,010
Contingency	$ 16,459,449	$ 397,634	$ 16,857,083
Total Project Cost	$ 97,413,639	$ 2,353,361	**$ 99,767,000**



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	$ 9,766,669	$ 7,411,786	$ 301,589	$ 5,970,964	$ 2,981,874	$ -	$ 5,623,242	**$ 32,056,124**
2.2.2 New 115KV Lines	$ 2,354,684	$ 2,729,159	$ 95,704	$ 1,894,789	$ 946,249	$ -	$ 1,784,445	**$ 9,805,030**
2.2.3 New 345KV Substations	$ 13,835,098	$ 2,251,239	$ 225,943	$ 4,473,294	$ 2,233,944	$ -	$ 4,212,790	**$ 27,232,308**
2.2.4 New 115KV Substations	$ 421,213	$ 82,344	$ 7,216	$ 142,860	$ 71,344	$ -	$ 134,541	**$ 859,517**
2.2.5 345 KV Substations Expansions/Modifications	$ 4,024,933	$ 526,333	$ 62,593	$ 1,239,247	$ 618,875	$ -	$ 1,167,079	**$ 7,639,060**
2.2.6 115 KV Substations Expansions/Modifications	$ 1,501,421	$ 239,278	$ 24,397	$ 483,022	$ 241,219	$ -	$ 454,893	**$ 2,944,229**
2.2.7 Lines Rerates, Relocations, Rebuilds	$ 4,668,327	$ 5,283,952	$ 186,646	$ 3,695,291	$ 1,845,412	$ -	$ 3,480,094	**$ 19,159,722**
Total	**$ 36,572,345**	**$ 18,524,090**	**$ 904,089**	**$ 17,899,466**	**$ 8,938,917**	**$ -**	**$ 16,857,083**	**$ 99,695,990**

Note: Values expressed in 2008 dollars.

2010 DEFERRED & OMITTED PROJECTS COST ESTIMATE & SCHEDULE SHEET

Transmission Owner:	**Central Maine Power**	**RSP Project #:**	**Various**
Project Name:	**Maine Power Reliability Program Deferred / Omitted**	**Date:**	**6/28/2010**
Estimate Grade:	**D (Construction)**		

1. 2010 Deferred & Omitted Project Scope Summary

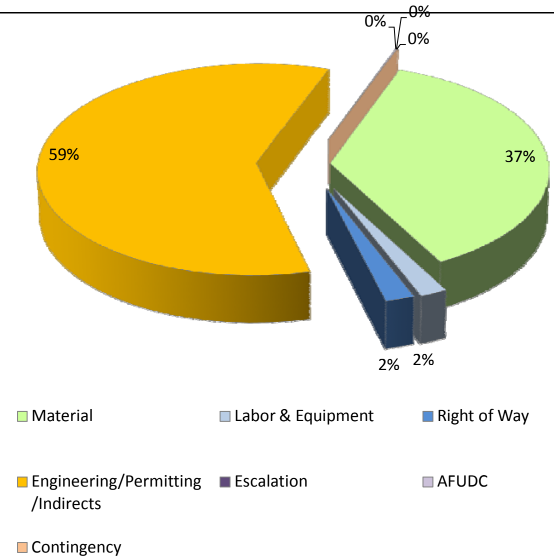
Central Maine Power plans to invest $1.5 billion to modernize our 40-year-old bulk power system. The proposed improvements are designed to keep the system operating reliably over the coming decades and to provide the infrastructure for the state's emerging wind, hydro, biomass, and tidal energy industries. The Maine Power Reliability Program will add to the company's network of substations and transmission lines that stretch from the Town of Eliot on the New Hampshire border to Orrington, where it connects to transmission lines from northern and eastern Maine. Central Maine Power filed for approval by the Maine Public Utilities Commission in July 2008. The project will also require approvals from the Maine Department of Environmental Protection and approximately 80 local governments and other agencies. The company expects to begin construction in 2010 for completion in 2015.

2. 2010 Deferred & Omitted Project Cost Summary

Prior Estimated Cost:

2.1. 2010 Deferred & Omitted Project Cost Summary

	PTF	Non-PTF	**Total**
Material	$ 1,343,911	$ 32,467	$ 1,376,378
Labor & Equipment	$ 68,686	$ 1,659	$ 70,345
Right of Way	$ 73,013	$ 1,764	$ 74,777
Engineering/Permitting /Indirects	$ 2,180,191	$ 52,670	$ 2,232,861
Escalation	$ -	$ -	$ -
AFUDC	$ 2,954	$ -	$ 2,954
Contingency	$ -	$ -	$ -
Total Project Cost	$ 3,668,756	$ 88,560	**$ 3,757,316**



2.2 2010 Detailed Cost Summary By Project Element

	Material	Labor & Equip.	Right of Way	Indirects	Escalation	AFUDC	Contingency	**Total**
2.2.1 New 345KV Lines	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
2.2.2 New 115KV Lines	$ 1,098,669	$ 56,152	$ 59,690	$ 1,782,341	$ -	$ -	$ -	**$ 2,996,851**
2.2.3 New 345KV Substations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
2.2.4 New 115KV Substations	$ 268,289	$ 13,712	$ 14,576	$ 435,238	$ -	$ -	$ -	**$ 731,815**
2.2.5 345 KV Substations Expansions/Modifications	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
2.2.6 115 KV Substations Expansions/Modifications	$ 9,420	$ 481	$ 512	$ 15,282	$ -	$ -	$ -	**$ 25,695**
2.2.7 Lines Rerates, Relocations, Rebuilds	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Total	**$ 1,376,378**	**$ 70,345**	**$ 74,777**	**$ 2,232,861**	**$ -**	**$ -**	**$ -**	**$ 3,754,362**

Note: Values expressed in 2008 dollars.

APPENDIX A – PROGRAM COST SUMMARY

MAINE POWER RELIABILITY PROGRAM (MPRP)
Program Cost Summary
as of 22-Jun-10

Central Maine Power
IBERDROLA USA

Settlement

Calendar Year	*Pre 2010 Total*	*2010*													*2011 Total*	*2012 Total*	*2013 Total*	*2014 Total*	*2015 Total*	*TOTAL*
		January	*February*	*March*	*April*	*May*	*June*	*July*	*August*	*September*	*October*	*November*	*December*	*2010 Total*						
Labor	$ 3,879,140	$ 105,398	$ 19,521	$ 41,527	$ 341,833	$ 451,052	$ 1,003,243	$ 3,733,867	$ 1,890,748	$ 3,703,502	$ 7,510,696	$ 6,325,430	$ 6,729,229	$ 31,856,046	$ 155,371,703	$ 212,435,673	$ 139,436,272	$ 35,989,821	$ -	$ 578,968,655
Material	$ 19,242,118	$ 2,291,207	$ 347,764	$ 48,245	$ 636,183	$ 368,765	$ 923,838	$ 676,141	$ 2,917,513	$ 5,311,614	$ 2,929,499	$ 5,349,788	$ 4,556,864	$ 26,357,421	$ 79,304,532	$ 92,375,257	$ 88,614,739	$ 25,696,262	$ (94,419)	$ 331,495,910
Right of Way	$ 15,672,494	$ 309,771	$ 511,682	$ 488,946	$ 2,563,173	$ 1,766,489	$ 2,443,609	$ 615,478	$ 2,422,818	$ 2,047,783	$ 2,231,153	$ 1,401,194	$ 695,679	$ 17,497,776	$ 1,679,641	$ -	$ -	$ -	$ -	$ 34,849,911
Engineering / Permitting / Indirects	$ 53,448,655	$ 2,152,255	$ 2,490,831	$ 2,850,869	$ (252,681)	$ 6,048,298	$ 2,131,432	$ 5,329,482	$ 2,536,900	$ 2,462,646	$ 2,520,624	$ 2,345,090	$ 2,558,003	$ 33,173,748	$ 21,118,736	$ 21,750,682	$ 16,198,548	$ 13,610,863	$ 10,026,234	$ 169,327,467
Escalation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,767,672	$ 26,004,594	$ 30,891,242	$ 34,375,538	$ 6,210,037	$ 104,249,083
AFUDC	$ 128,996	$ 1,391	$ (133)	$ 901	$ 1,158	$ 1,744	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,062	$ -	$ -	$ -	$ -	$ -	$ 134,057
Contingency	$ -	$ -	$ -	$ -	$ -	$ -	$ 886,301	$ 250,000	$ 2,000,000	$ 3,000,000	$ 2,500,000	$ 1,447,567	$ 500,000	$ 10,583,868	$ 37,633,394	$ 56,584,297	$ 50,157,174	$ 30,508,034	$ 430,150	$ 185,896,917
Total	$ 92,371,403	$ 4,860,022	$ 3,369,666	$ 3,430,488	$ 3,289,666	$ 8,636,348	$ 7,388,423	$ 10,604,968	$ 11,767,979	$ 16,525,545	$ 17,691,972	$ 16,869,069	$ 15,039,775	$ 119,473,921	$ 301,875,678	$ 409,150,503	$ 325,297,975	$ 140,180,518	$ 16,572,002	$ 1,404,922,000

Deferred

Calendar Year	*Pre 2010 Total*	*2010*													*2011 Total*	*2012 Total*	*2013 Total*	*2014 Total*	*2015 Total*	*TOTAL*
		January	*February*	*March*	*April*	*May*	*June*	*July*	*August*	*September*	*October*	*November*	*December*	*2010 Total*						
Labor		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 70,345	$ 70,345	$ 12,375,500	$ 10,375,500	$ 8,375,500	$ 5,375,500	$ -	$ 36,572,345
Material		$ -	$ -	$ -	$ -	$ -	$ -	$ 94,225	$ 180,256	$ 172,062	$ 172,062	$ 227,287	$ 530,486	$ 1,376,378	$ 5,667,750	$ 5,250,035	$ 3,607,750	$ 2,622,177	$ -	$ 18,524,090
Right of Way	$ 829,312	$ 23,829	$ 2,936	$ 52,295	$ (4,837)	$ 554	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 74,777	$ -	$ -	$ -	$ -	$ -	$ 904,089
Engineering / Permitting / Indirects	$ 468,605	$ 826	$ 41,735	$ 9,924	$ 5,218	$ 3,858	$ 322,761	$ 308,090	$ 322,761	$ 308,090	$ 308,090	$ 293,419	$ 308,090	$ 2,232,861	$ 3,799,500	$ 3,799,500	$ 3,799,500	$ 3,799,500	$ -	$ 17,899,466
Escalation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,234,729	$ 2,234,729	$ 2,234,729	$ 2,234,729	$ -	$ 8,938,917
AFUDC	$ 68,055	$ 1,220	$ (616)	$ 191	$ 208	$ 202	$ 250	$ 250	$ 250	$ 250	$ 250	$ 250	$ 250	$ 2,955	$ -	$ -	$ -	$ -	$ -	$ 71,010
Contingency	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,292,271	$ 3,980,271	$ 4,292,271	$ 4,292,271	$ -	$ 16,857,083
Total	$ 1,365,971	$ 25,874	$ 44,056	$ 62,409	$ 590	$ 4,613	$ 323,011	$ 402,565	$ 503,267	$ 480,402	$ 480,402	$ 520,956	$ 909,171	$ 3,757,316	$ 28,369,750	$ 25,640,035	$ 22,309,750	$ 18,324,177	$ -	$ 99,767,000

Combined

Calendar Year	*Pre 2010 Total*	*2010*													*2011 Total*	*2012 Total*	*2013 Total*	*2014 Total*	*2015 Total*	*TOTAL*
		January	*February*	*March*	*April*	*May*	*June*	*July*	*August*	*September*	*October*	*November*	*December*	*2010 Total*						
Labor	$ 3,879,140	$ 105,398	$ 19,521	$ 41,527	$ 341,833	$ 451,052	$ 1,003,243	$ 3,733,867	$ 1,890,748	$ 3,703,502	$ 7,510,696	$ 6,325,430	$ 6,799,574	$ 31,926,391	$ 167,747,203	$ 222,811,173	$ 147,811,772	$ 41,365,321	$ -	$ 615,541,000
Material	$ 19,242,118	$ 2,291,207	$ 347,764	$ 48,245	$ 636,183	$ 368,765	$ 923,838	$ 770,366	$ 3,097,769	$ 5,483,676	$ 3,101,561	$ 5,577,075	$ 5,087,350	$ 27,733,799	$ 84,972,282	$ 97,625,292	$ 92,222,489	$ 28,318,439	$ (94,419)	$ 350,020,000
Right of Way	$ 16,501,806	$ 333,600	$ 514,619	$ 541,241	$ 2,558,336	$ 1,767,043	$ 2,443,609	$ 615,478	$ 2,422,818	$ 2,047,783	$ 2,231,153	$ 1,401,194	$ 695,679	$ 17,572,553	$ 1,679,641	$ -	$ -	$ -	$ -	$ 35,754,000
Engineering / Permitting / Indirects	$ 53,917,260	$ 2,153,081	$ 2,532,566	$ 2,860,792	$ (247,463)	$ 6,052,156	$ 2,454,193	$ 5,637,572	$ 2,859,661	$ 2,770,736	$ 2,828,714	$ 2,638,509	$ 2,866,093	$ 35,406,610	$ 24,918,236	$ 25,550,182	$ 19,998,048	$ 17,410,363	$ 10,026,234	$ 187,226,933
Escalation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,002,401	$ 28,239,323	$ 33,125,971	$ 36,610,267	$ 6,210,037	$ 113,188,000
AFUDC	$ 197,051	$ 2,611	$ (749)	$ 1,092	$ 1,366	$ 1,945	$ 250	$ 250	$ 250	$ 250	$ 250	$ 250	$ 250	$ 8,016	$ -	$ -	$ -	$ -	$ -	$ 205,067
Contingency	$ -	$ -	$ -	$ -	$ -	$ -	$ 886,301	$ 250,000	$ 2,000,000	$ 3,000,000	$ 2,500,000	$ 1,447,567	$ 500,000	$ 10,583,868	$ 41,925,665	$ 60,564,568	$ 54,449,445	$ 34,800,305	$ 430,150	$ 202,754,000
Total	$ 93,737,375	$ 4,885,897	$ 3,413,721	$ 3,492,898	$ 3,290,255	$ 8,640,961	$ 7,711,434	$ 11,007,533	$ 12,271,246	$ 17,005,947	$ 18,172,374	$ 17,390,025	$ 15,948,946	$ 123,231,237	$ 330,245,428	$ 434,790,538	$ 347,607,725	$ 158,504,695	$ 16,572,002	$ 1,504,689,000

APPENDIX B – MPRP COSTS THROUGH 2010 FOR CWIP FILING

MPRP Costs Through 2010 for CWIP Filing

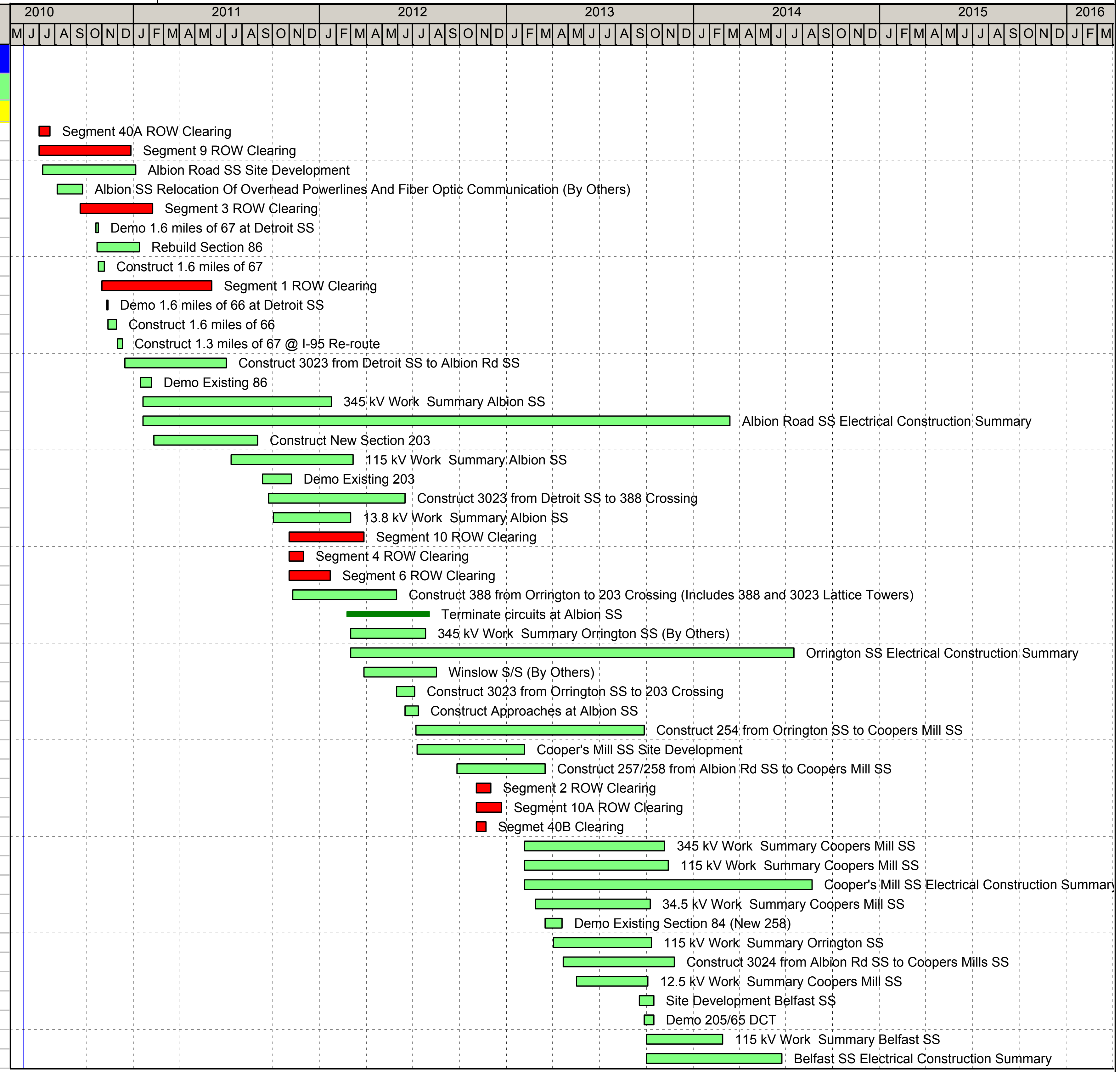
	Total	PTF	Non-PTF	Distribution	
MPRP (Less Lewiston and So. Gorham) Total Cost Through 2009 (Including Land):	$ 69,051,354	$ 67,463,173	$ 1,201,494	$ 386,688	$ 68,664,666
Total Land Acquisition Costs Through 2009 in Plant Held for Future Use:	$ 15,804,819	$ 15,441,308	$ 363,511		$ 15,804,819
Total Less Land Through 2009:	$ 53,246,535	$ 52,021,865	$ 837,983		$ 52,859,848
Projected MPRP Cost Including South Gorham Not In Service for 2010 & Excluding Lewiston	$ 114,873,921	$ 112,126,020	$ 2,078,846	$ 669,054	$ 114,204,867
Projected Land Cost for MPRP for 2010	$ 21,600,000	$ 21,103,200	$ 496,800		
Total MPRP Cost (Excluding Lewiston and South Gorham 2010 In Service) Less Land	$ 93,273,921	$ 91,022,820	$ 1,582,046		
				$ 1,055,742	
South Gorham					
$22.4M entered svc in 09. 0.9M additional spending included CWIP		$ 22,435,778	('09 in svc)		
Total South Gorham Cost Through 2009 (Including Transformer):	$ 23,320,049	$ 23,320,049			$ 884,271
Transformer:	$ 5,240,930	$ 5,240,930			
Total South Gorham Cost Through 2009 Less Transformer	$ 18,079,119	$ 18,079,119			
South Gorham In Service in 2010	$ 4,600,000	$ 4,600,000			
Total MPRP Cost Through 2010	$ 211,845,324				
Total Recoverable Through Tranmission Rates	$ 210,789,582			$ 209,773,840	
				$ 210,618,111	
Total Cost for 2010, Excluding Lewistion	$ 119,473,921				
Total Forecasted MPRP CWIP for 2010:	**$ 183,753,804**	**$ 180,473,464**	**$ 3,280,340**		

APPENDIX C – CONSTRUCTION SCHEDULE BY LOOP

Maine Power Reliability Program

Construction Schedule

Activity Name	Original Duration	Start	Finish
Maine Power Reliability Program	1236	30-Jun-10	11-May-15
CONSTRUCTION	1236	30-Jun-10	11-May-15
NORTHERN LOOP	1053	30-Jun-10	20-Aug-14
Segment 40A ROW Clearing	15	30-Jun-10*	21-Jul-10
Segment 9 ROW Clearing	124	30-Jun-10*	27-Dec-10
Albion Road SS Site Development	125	08-Jul-10	05-Jan-11
Albion SS Relocation Of Overhead Powerlines And Fiber Optic Communication (By Othe	36	05-Aug-10	24-Sep-10
Segment 3 ROW Clearing	97	20-Sep-10*	07-Feb-11
Demo 1.6 miles of 67 at Detroit SS	4	20-Oct-10	23-Oct-10
Rebuild Section 86	70	21-Oct-10	13-Jan-11
Construct 1.6 miles of 67	12	25-Oct-10	06-Nov-10
Segment 1 ROW Clearing	150	01-Nov-10*	03-Jun-11
Demo 1.6 miles of 66 at Detroit SS	4	09-Nov-10	12-Nov-10
Construct 1.6 miles of 66	12	13-Nov-10	29-Nov-10
Construct 1.3 miles of 67 @ I-95 Re-route	10	01-Dec-10	11-Dec-10
Construct 3023 from Detroit SS to Albion Rd SS	170	15-Dec-10	02-Jul-11
Demo Existing 86	20	14-Jan-11	05-Feb-11
345 kV Work Summary Albion SS	256	20-Jan-11	23-Jan-12
Albion Road SS Electrical Construction Summary	803	20-Jan-11	12-Mar-14
Construct New Section 203	175	09-Feb-11	02-Sep-11
115 kV Work Summary Albion SS	167	11-Jul-11	06-Mar-12
Demo Existing 203	50	10-Sep-11	07-Nov-11
Construct 3023 from Detroit SS to 388 Crossing	225	22-Sep-11	15-Jun-12
13.8 kV Work Summary Albion SS	105	03-Oct-11	01-Mar-12
Segment 10 ROW Clearing	101	01-Nov-11*	26-Mar-12
Segment 4 ROW Clearing	20	01-Nov-11*	30-Nov-11
Segment 6 ROW Clearing	55	01-Nov-11*	20-Jan-12
Construct 388 from Orrington to 203 Crossing (Includes 388 and 3023 Lattice Towers)	170	08-Nov-11	29-May-12
Terminate circuits at Albion SS	135	24-Feb-12	01-Aug-12
345 kV Work Summary Orrington SS (By Others)	105	29-Feb-12	26-Jul-12
Orrington SS Electrical Construction Summary	609	29-Feb-12	15-Jul-14
Winslow S/S (By Others)	100	27-Mar-12*	15-Aug-12
Construct 3023 from Orrington SS to 203 Crossing	30	30-May-12	03-Jul-12
Construct Approaches at Albion SS	20	16-Jun-12	10-Jul-12
Construct 254 from Orrington SS to Coopers Mill SS	375	07-Jul-12	26-Sep-13
Cooper's Mill SS Site Development	145	10-Jul-12	04-Feb-13
Construct 257/258 from Albion Rd SS to Coopers Mill SS	145	24-Sep-12*	15-Mar-13
Segment 2 ROW Clearing	20	01-Nov-12*	30-Nov-12
Segment 10A ROW Clearing	35	01-Nov-12*	21-Dec-12
Segmet 40B Clearing	15	01-Nov-12*	21-Nov-12
345 kV Work Summary Coopers Mill SS	195	05-Feb-13	05-Nov-13
115 kV Work Summary Coopers Mill SS	199	05-Feb-13	11-Nov-13
Cooper's Mill SS Electrical Construction Summary	473	05-Feb-13	20-Aug-14
34.5 kV Work Summary Coopers Mill SS	160	26-Feb-13	08-Oct-13
Demo Existing Section 84 (New 258)	30	16-Mar-13	19-Apr-13
115 kV Work Summary Orrington SS	137	02-Apr-13	10-Oct-13
Construct 3024 from Albion Rd SS to Coopers Mills SS	185	20-Apr-13	25-Nov-13
12.5 kV Work Summary Coopers Mill SS	100	16-May-13	03-Oct-13
Site Development Belfast SS	20	17-Sep-13	14-Oct-13
Demo 205/65 DCT	15	27-Sep-13	14-Oct-13
115 kV Work Summary Belfast SS	105	01-Oct-13	26-Feb-14
Belfast SS Electrical Construction Summary	188	01-Oct-13	23-Jun-14



Print Date: 18-Jun-10

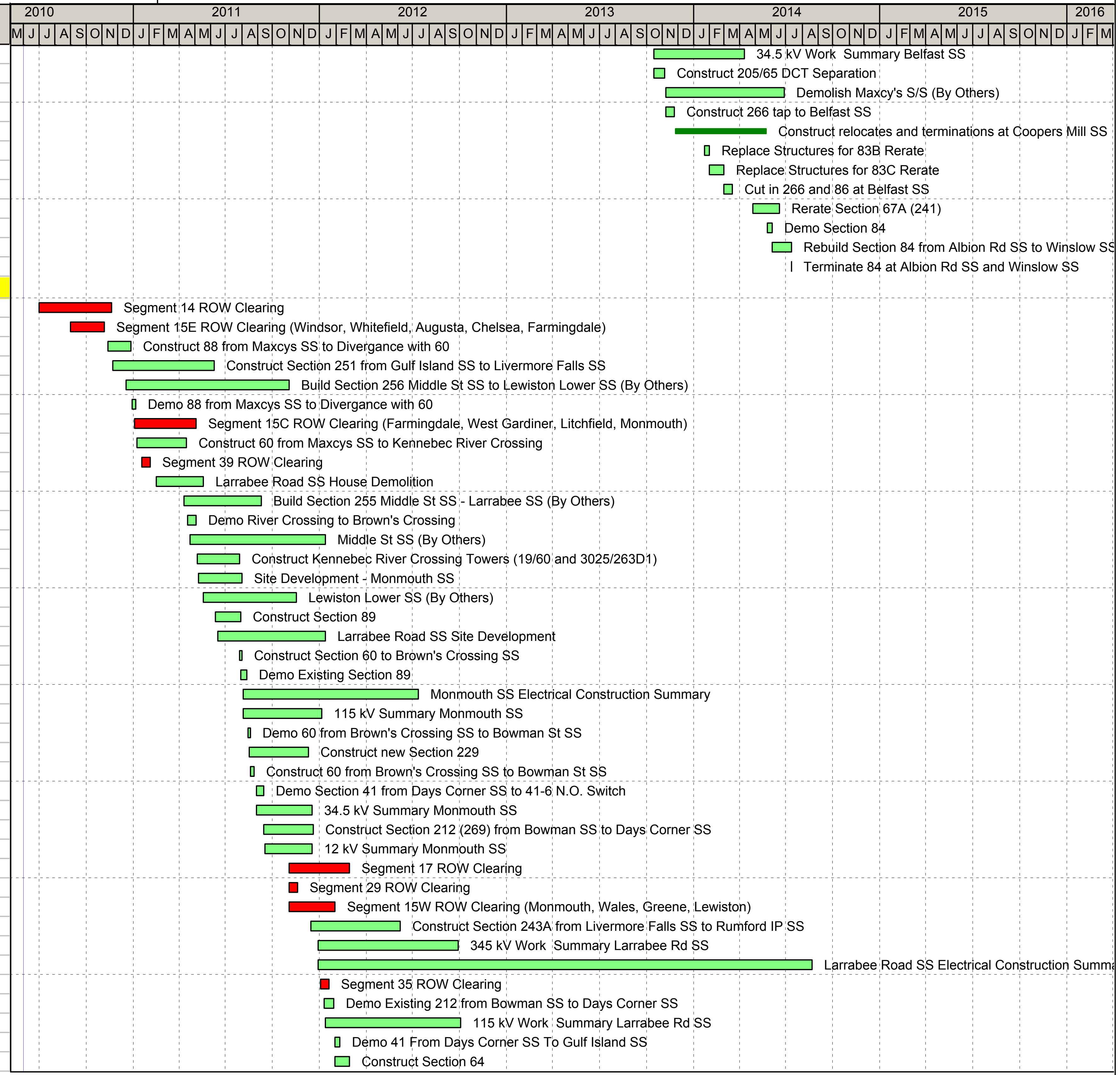
Data Date: 01-Jun-10

Sorted By Loop Then Start Date

Maine Power Reliability Program

Construction Schedule

Activity Name	Original Duration	Start	Finish
34.5 kV Work Summary Belfast SS	127	15-Oct-13	11-Apr-14
Construct 205/65 DCT Separation	18	15-Oct-13	04-Nov-13
Demolish Maxcy's S/S (By Others)	165	07-Nov-13	27-Jun-14
Construct 266 tap to Belfast SS	15	07-Nov-13	23-Nov-13
Construct relocates and terminations at Coopers Mill SS	150	26-Nov-13	23-May-14
Replace Structures for 83B Rerate	8	23-Jan-14	31-Jan-14
Replace Structures for 83C Rerate	24	01-Feb-14	28-Feb-14
Cut in 266 and 86 at Belfast SS	14	01-Mar-14	17-Mar-14
Rerate Section 67A (241)	45	26-Apr-14	18-Jun-14
Demo Section 84	7	24-May-14	02-Jun-14
Rebuild Section 84 from Albion Rd SS to Winslow SS	33	03-Jun-14	11-Jul-14
Terminate 84 at Albion Rd SS and Winslow SS	1	11-Jul-14	11-Jul-14
CENTRAL LOOP	**1236**	**30-Jun-10**	**11-May-15**
Segment 14 ROW Clearing	122	30-Jun-10*	20-Nov-10
Segment 15E ROW Clearing (Windsor, Whitefield, Augusta, Chelsea, Farmingdale)	55	01-Sep-10*	04-Nov-10
Construct 88 from Maxcys SS to Divergance with 60	35	13-Nov-10	27-Dec-10
Construct Section 251 from Gulf Island SS to Livermore Falls SS	168	22-Nov-10	09-Jun-11
Build Section 256 Middle St SS to Lewiston Lower SS (By Others)	223	17-Dec-10*	01-Nov-11
Demo 88 from Maxcys SS to Divergance with 60	7	30-Dec-10	06-Jan-11
Segment 15C ROW Clearing (Farmingdale, West Gardiner, Litchfield, Monmouth)	105	03-Jan-11*	04-May-11
Construct 60 from Maxcys SS to Kennebec River Crossing	85	07-Jan-11	15-Apr-11
Segment 39 ROW Clearing	15	17-Jan-11*	02-Feb-11
Larrabee Road SS House Demolition	65	16-Feb-11	17-May-11
Build Section 255 Middle St SS - Larrabee SS (By Others)	107	11-Apr-11*	09-Sep-11
Demo River Crossing to Brown's Crossing	15	18-Apr-11	04-May-11
Middle St SS (By Others)	183	22-Apr-11*	12-Jan-12
Construct Kennebec River Crossing Towers (19/60 and 3025/263D1)	70	05-May-11	27-Jul-11
Site Development - Monmouth SS	60	09-May-11	02-Aug-11
Lewiston Lower SS (By Others)	127	19-May-11*	16-Nov-11
Construct Section 89	41	11-Jun-11	29-Jul-11
Larrabee Road SS Site Development	145	15-Jun-11	11-Jan-12
Construct Section 60 to Brown's Crossing SS	5	28-Jul-11	02-Aug-11
Demo Existing Section 89	10	30-Jul-11	10-Aug-11
Monmouth SS Electrical Construction Summary	239	03-Aug-11	11-Jul-12
115 kV Summary Monmouth SS	105	03-Aug-11	03-Jan-12
Demo 60 from Brown's Crossing SS to Bowman St SS	5	13-Aug-11	18-Aug-11
Construct new Section 229	98	16-Aug-11	10-Dec-11
Construct 60 from Brown's Crossing SS to Bowman St SS	5	19-Aug-11	24-Aug-11
Demo Section 41 from Days Corner SS to 41-6 N.O. Switch	10	31-Aug-11	12-Sep-11
34.5 kV Summary Monmouth SS	75	31-Aug-11	16-Dec-11
Construct Section 212 (269) from Bowman SS to Days Corner SS	82	13-Sep-11	19-Dec-11
12 kV Summary Monmouth SS	65	15-Sep-11	16-Dec-11
Segment 17 ROW Clearing	98	01-Nov-11*	27-Feb-12
Segment 29 ROW Clearing	15	01-Nov-11*	17-Nov-11
Segment 15W ROW Clearing (Monmouth, Wales, Greene, Lewiston)	75	01-Nov-11*	31-Jan-12
Construct Section 243A from Livermore Falls SS to Rumford IP SS	146	15-Dec-11	05-Jun-12
345 kV Work Summary Larrabee Rd SS	193	28-Dec-11	27-Sep-12
Larrabee Road SS Electrical Construction Summary	678	28-Dec-11	19-Aug-14
Segment 35 ROW Clearing	15	03-Jan-12*	19-Jan-12
Demo Existing 212 from Bowman SS to Days Corner SS	18	09-Jan-12	28-Jan-12
115 kV Work Summary Larrabee Rd SS	185	12-Jan-12	01-Oct-12
Demo 41 From Days Corner SS To Gulf Island SS	10	30-Jan-12	09-Feb-12
Construct Section 64	25	30-Jan-12	27-Feb-12



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Sorted By Loop Then Start Date

MAINE POWER RELIABILITY PROGRAM
A CENTRAL MAINE POWER COMPANY PROGRAM

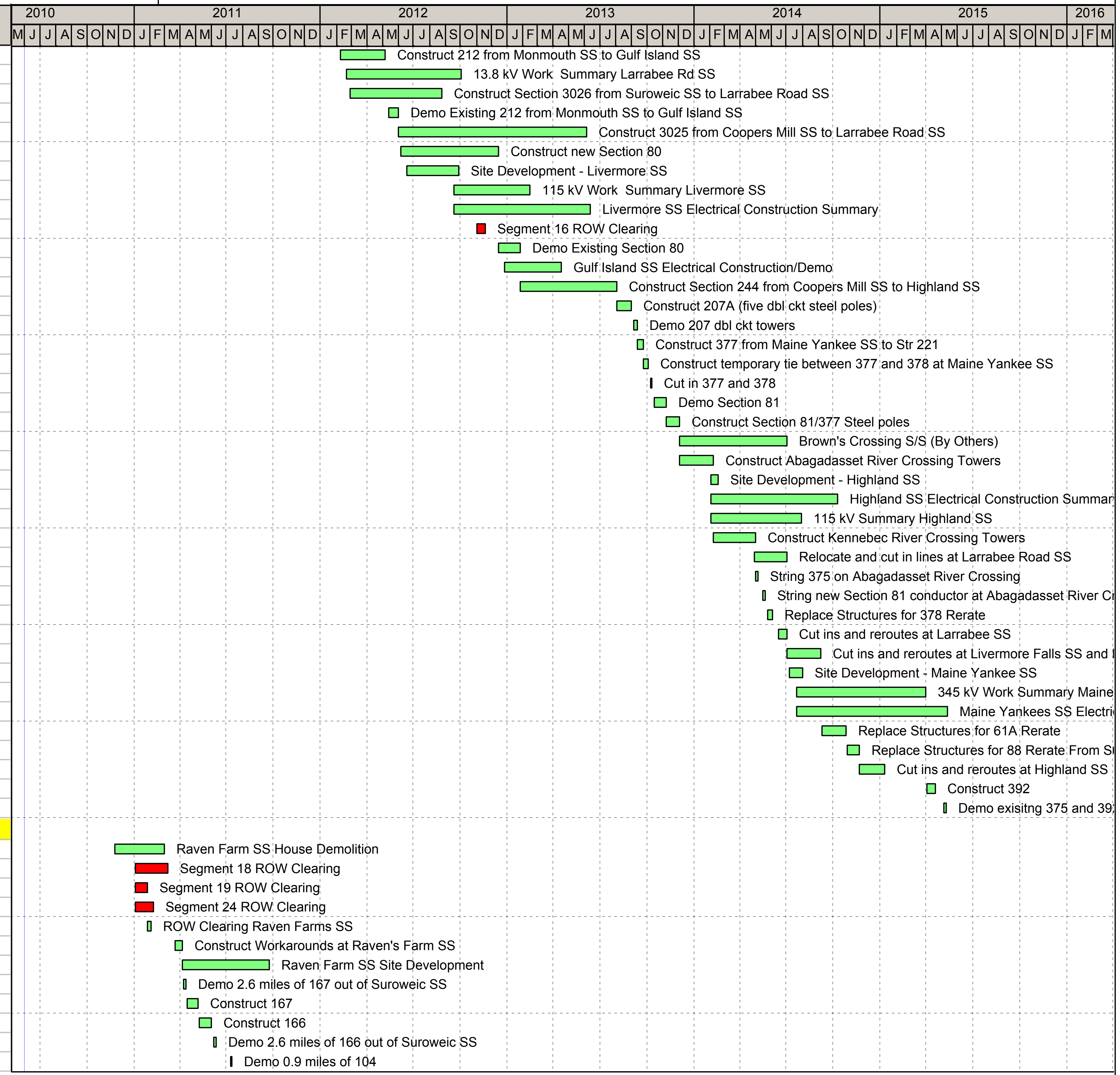
Burns & McDonnell
SINCE 1898

Central Maine Power
IBERDROLA USA

Maine Power Reliability Program

Construction Schedule

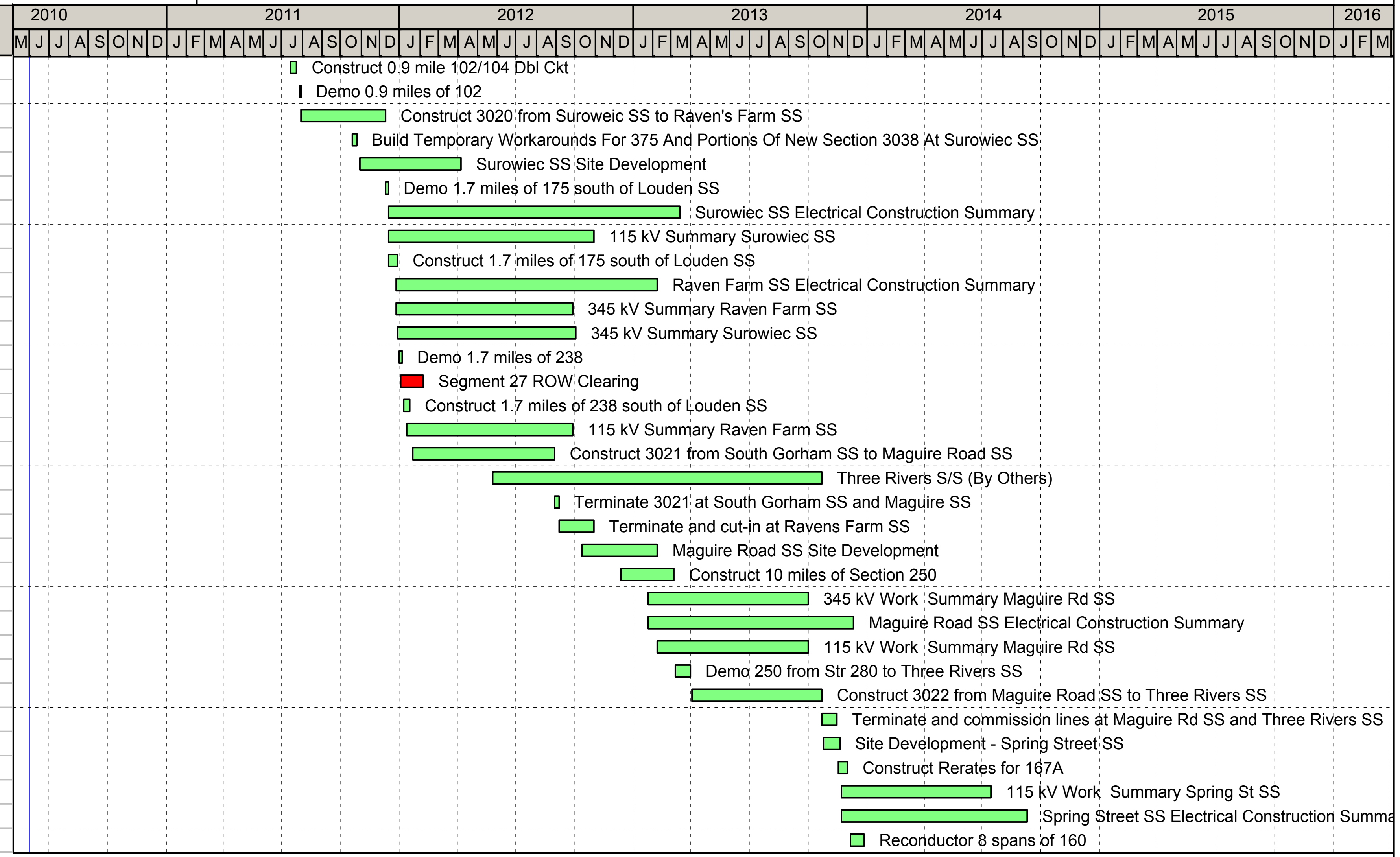
Activity Name	Original Duration	Start	Finish
Construct 212 from Monmouth SS to Gulf Island SS	75	10-Feb-12	07-May-12
13.8 kV Work Summary Larrabee Rd SS	157	21-Feb-12	01-Oct-12
Construct Section 3026 from Suroweic SS to Larrabee Road SS	153	28-Feb-12	25-Aug-12
Demo Existing 212 from Monmouth SS to Gulf Island SS	16	14-May-12	01-Jun-12
Construct 3025 from Coopers Mill SS to Larrabee Road SS	308	02-Jun-12	04-Jun-13
Construct new Section 80	160	07-Jun-12	14-Dec-12
Site Development - Livermore SS	73	18-Jun-12	28-Sep-12
115 kV Work Summary Livermore SS	105	17-Sep-12	14-Feb-13
Livermore SS Electrical Construction Summary	189	17-Sep-12	12-Jun-13
Segment 16 ROW Clearing	15	01-Nov-12*	17-Nov-12
Demo Existing Section 80	34	15-Dec-12	25-Jan-13
Gulf Island SS Electrical Construction/Demo	78	26-Dec-12	15-Apr-13
Construct Section 244 from Coopers Mill SS to Highland SS	160	26-Jan-13	02-Aug-13
Construct 207A (five dbl ckt steel poles)	25	03-Aug-13*	31-Aug-13
Demo 207 dbl ckt towers	5	06-Sep-13	11-Sep-13
Construct 377 from Maine Yankee SS to Str 221	10	12-Sep-13	23-Sep-13
Construct temporary tie between 377 and 378 at Maine Yankee SS	10	24-Sep-13	04-Oct-13
Cut in 377 and 378	5	07-Oct-13	11-Oct-13
Demo Section 81	20	16-Oct-13	07-Nov-13
Construct Section 81/377 Steel poles	20	08-Nov-13	03-Dec-13
Brown's Crossing S/S (By Others)	150	03-Dec-13	02-Jul-14
Construct Abagadasset River Crossing Towers	55	04-Dec-13	07-Feb-14
Site Development - Highland SS	10	04-Feb-14	17-Feb-14
Highland SS Electrical Construction Summary	176	04-Feb-14	08-Oct-14
115 kV Summary Highland SS	125	04-Feb-14	29-Jul-14
Construct Kennebec River Crossing Towers	70	08-Feb-14	30-Apr-14
Relocate and cut in lines at Larrabee Road SS	54	30-Apr-14	02-Jul-14
String 375 on Abagadasset River Crossing	5	01-May-14	06-May-14
String new Section 81 conductor at Abagadasset River Crossing	5	15-May-14	20-May-14
Replace Structures for 378 Rerate	7	24-May-14	02-Jun-14
Cut ins and reroutes at Larrabee SS	15	16-Jun-14	02-Jul-14
Cut ins and reroutes at Livermore Falls SS and Rumford IP SS	54	03-Jul-14	05-Sep-14
Site Development - Maine Yankee SS	20	07-Jul-14	01-Aug-14
345 kV Work Summary Maine Yankee SS	180	21-Jul-14	31-Mar-15
Maine Yankees SS Electrical Construction Summary	209	21-Jul-14	11-May-15
Replace Structures for 61A Rerate	42	08-Sep-14	25-Oct-14
Replace Structures for 88 Rerate From S60 Divergence To Augusta E. Side	20	29-Oct-14	20-Nov-14
Cut ins and reroutes at Highland SS	40	21-Nov-14	10-Jan-15
Construct 392	15	01-Apr-15	17-Apr-15
Demo exisitng 375 and 392	5	05-May-15	09-May-15
SOUTHERN LOOP/SOUTHERN CONNECTOR	**962**	**24-Nov-10**	**08-Sep-14**
Raven Farm SS House Demolition	65	24-Nov-10	28-Feb-11
Segment 18 ROW Clearing	55	03-Jan-11*	07-Mar-11
Segment 19 ROW Clearing	22	03-Jan-11*	27-Jan-11
Segment 24 ROW Clearing	32	03-Jan-11*	08-Feb-11
ROW Clearing Raven Farms SS	5	28-Jan-11	03-Feb-11
Construct Workarounds at Raven's Farm SS	13	22-Mar-11	05-Apr-11
Raven Farm SS Site Development	120	06-Apr-11	23-Sep-11
Demo 2.6 miles of 167 out of Suroweic SS	6	07-Apr-11	13-Apr-11
Construct 167	19	14-Apr-11	05-May-11
Construct 166	19	09-May-11	31-May-11
Demo 2.6 miles of 166 out of Suroweic SS	6	06-Jun-11	11-Jun-11
Demo 0.9 miles of 104	3	09-Jul-11	12-Jul-11



Maine Power Reliability Program

Construction Schedule

Activity Name	Original Duration	Start	Finish
Construct 0.9 mile 102/104 Dbl Ckt	10	13-Jul-11	23-Jul-11
Demo 0.9 miles of 102	3	27-Jul-11	29-Jul-11
Construct 3020 from Suroweic SS to Raven's Farm SS	111	30-Jul-11	09-Dec-11
Build Temporary Workarounds For 375 And Portions Of New Section 3038 At Surowiec SS	7	18-Oct-11	25-Oct-11
Surowiec SS Site Development	110	31-Oct-11	05-Apr-12
Demo 1.7 miles of 175 south of Louden SS	4	10-Dec-11	14-Dec-11
Surowiec SS Electrical Construction Summary	317	14-Dec-11	13-Mar-13
115 kV Summary Surowiec SS	225	14-Dec-11	30-Oct-12
Construct 1.7 miles of 175 south of Louden SS	12	15-Dec-11	29-Dec-11
Raven Farm SS Electrical Construction Summary	285	27-Dec-11	07-Feb-13
345 kV Summary Raven Farm SS	195	27-Dec-11	28-Sep-12
345 kV Summary Surowiec SS	195	29-Dec-11	02-Oct-12
Demo 1.7 miles of 238	4	31-Dec-11	05-Jan-12
Segment 27 ROW Clearing	30	03-Jan-12*	06-Feb-12
Construct 1.7 miles of 238 south of Louden SS	10	06-Jan-12	17-Jan-12
115 kV Summary Raven Farm SS	185	11-Jan-12	28-Sep-12
Construct 3021 from South Gorham SS to Maguire Road SS	189	20-Jan-12	29-Aug-12
Three Rivers S/S (By Others)	360	25-May-12	22-Oct-13
Terminate 3021 at South Gorham SS and Maguire SS	5	30-Aug-12	05-Sep-12
Terminate and cut-in at Ravens Farm SS	46	06-Sep-12	30-Oct-12
Maguire Road SS Site Development	80	12-Oct-12	06-Feb-13
Construct 10 miles of Section 250	70	11-Dec-12	04-Mar-13
345 kV Work Summary Maguire Rd SS	176	24-Jan-13	30-Sep-13
Maguire Road SS Electrical Construction Summary	229	24-Jan-13	11-Dec-13
115 kV Work Summary Maguire Rd SS	166	07-Feb-13	30-Sep-13
Demo 250 from Str 280 to Three Rivers SS	20	08-Mar-13	30-Mar-13
Construct 3022 from Maguire Road SS to Three Rivers SS	173	01-Apr-13	22-Oct-13
Terminate and commission lines at Maguire Rd SS and Three Rivers SS	20	23-Oct-13	14-Nov-13
Site Development - Spring Street SS	20	24-Oct-13	20-Nov-13
Construct Rerates for 167A	12	16-Nov-13	02-Dec-13
115 kV Work Summary Spring St SS	165	21-Nov-13	14-Jul-14
Spring Street SS Electrical Construction Summary	205	21-Nov-13	08-Sep-14
Reconductor 8 spans of 160	20	05-Dec-13	28-Dec-13



Sorted By Loop Then Start Date

CMEEC 2009 PTF Support Payments and Revenue Requirements

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)	$55,342	
Support Payments to Boston Edison Company for Hydro-Quebec Phase II A.C. Transmission Facilities (Attachment F, Item K)	$4,268	
Support Payments to New England Hydro-Transmission Corporation for Hydro-Quebec Phase II Chester SVC Facility (Attachment F, Item K)	$25,879	
Revenue Requirements for Town of Wallingford, Electric Div. PTF Facilities	$80,603	$628,370
Revenue Requirements for Mohegan Tribal Utility Authority's PTF Facilities		$322,101
Revenue Requirements for City of Groton, Department of Utilities PTF Facilities		$161,198
Revenue Requirements for Norwich, Department of Utilities PTF Facilities	$37,539	
Total Support Payments and Revenue Requirements Less Revenues	**$203,631**	**$1,111,669**

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 17, 2010
Revenue Requirements for (year):	Calendar Year 2008
Customer:	City of Groton, Dept. of Utilities
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	=	0	(a)	161,198	(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)	161,198	(j)

Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:	161,198	(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)	161,198	(l)=(k)+(b)+(g)-(h)

City of Groton, Dept. of Utilities

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Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	GROTON	Reference
1	Transmission Plant	(A)(1)(a)	2,051,470	Worksheet 3, L10
2	General Plant	(A)(1)(b)	21,151	Worksheet 3, L11
3	Plant Held For Future Use	(A)(1)(c)	0	Worksheet 3, L14
4	Total Plant (Lines 1+2+3)		2,072,621	
5	Accumulated Depreciation	(A)(1)(d)	1,783,031	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)		289,590	
10	Prepayments	(A)(1)(h)	0	Worksheet 3, L34
11	Materials & Supplies	(A)(1)(i)	78,809	Worksheet 3, L36
12	Cash Working Capital	(A)(1)(j)	3,592	Worksheet 3, 44
13	Total Investment Base (Line 9+10+11+12)		371,991	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	29,759	Worksheet 2, E56
15	Depreciation Expense	(B)	57,670	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)	44,138	Worksheet 4, L21
19	Payroll Tax Expense	(F)	897	Worksheet 4, L42
20	Operation & Maintenance Expense	(G)	13,110	Worksheet 4, L29
21	Administrative & General Expense	(H)	15,624	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)		161,198	

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		CAPITALIZATION 12/31/2009	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	0	0.00%	6.03%	0.00%	
PREFERRED STOCK		0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY		26,673,884	100.00%	8.00%	8.00%	8.00%
TOTAL INVESTMENT RETURN	$	26,673,884	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	$	371,991	From Worksheet 1
x Cost of Capital Rate		8.00%	
= Investment Return and Income Taxes		29,759	To Worksheet 1

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

Line No.		(1) Total F	(2) Wage/Plant Allocation actors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Reference
	Transmission Plant						
1	Transmission Plant	7,560,499		7,560,499		$ 2,051,470	Used RSI numbers
2	General Plant	7,632,634	1.0213% (a)	77,952		21,151	DPUC Report-Page 502
3	Total (line 1+2)			7,638,451		2,072,621	
4	Transmission Plant Held for Future Use	0		0	27.1340%	0	None known
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	6,522,581		6,522,581	27.1340%	1,769,837	Used RSI Methodolgy
6	General Plant Accum.Depreciation	4,760,994	1.0213% (a)	48,624	27.1340%	13,194	Used RSI Methodolgy
7	Total (line 5+6)			6,571,205		1,783,031	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes	0	14.2093% (c)	0	27.1340%	0	None known
9	Accumulated Deferred Taxes	0	14.2093% (c)	0	27.1340%	0	None known
10	Total (line 8+9)			0		0	
11	Transmission loss on Reacquired Debt	0	14.2093% (c)	0	27.1340%	0	None known
	Other Regulatory Assets						
12	FAS 106	0	1.0213% (a)	0	27.1340%	0	None known
13	FAS 109	0	14.2093% (c)	0	27.1340%	0	None known
14	Other Regulatory Liabilities (254.DK)	0	14.2093% (c)	0	27.1340%	0	
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments	0	1.0213% (a)	0	27.1340%	0	Assumed none
17	Transmission Materials and Supplies	2,044,028	14.2093%	290,442	27.1340%	78,809	DPUC report-Page 200
18	Cash Working Capital						
19	Operation & Maintenance Expense					13,110	Worksheet 1, Line 20
20	Administrative & General Expense					15,624	Worksheet 1, Line 21
21	Transmission Support Expense					0	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					28,734	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					3,592	

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

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

Line (No.		1) Total F	(2) Wage/Plant Allocation actors		(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Reference
	Depreciation Expense							
1	Transmission Depreciation	210,367			210,367	27.1340%	57,081	
2	General Depreciation	212,374	1.0213%	(a)	2,169	27.1340%	589	DPUC Report Page 508
3	Total (line 1+2)				212,536		57,670	
4	Amortization of Loss on Reacquired Debt	0	14.2093%	(c)	0	27.1340%	0	None known
5	Amortization of Investment Tax Credits	0	14.2093%	(c)	0	27.1340%	0	None known
	Property Taxes *							
6	Transmission Property Taxes	1,144,784	14.2093%		162,666	27.1340%	44,138	See below
7	General Property Taxes	0	1.0213%	(a)	0	27.1340%	0	See below
8	Total (line 6+7)				162,666		44,138	
	Transmission Operation and Maintenance							
9	Operation and Maintenance	60,534			60,534	27.1340%	16,425	DPUC Report-Page 518
10	Transmission of Electricity by Others - #565	0			0	27.1340%	0	
11	Load Dispatching - #561	0			0	27.1340%	0	
12	**Station Expenses & Rents - #562 / #567	12,217			12,217	27.1340%	3,315	DPUC Report-Page 518
13	O&M less lines 10, 11 & 12	48,317			48,317	27.1340%	13,110	
	Transmission Administrative and General							
14	Administrative and General	4,284,067						DPUC Report-Page 520
15	less Property Insurance (#924)	104,829						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)]	4,179,238	1.0213%	(a)	42,683	27.1340%	11,582	
19	PLUS Property Insurance alloc. using Plant Allocatior	104,829	14.2093%	(c)	14,895	27.1340%	4,042	
20	PLUS Regulatory Comm. Exp. (FERC Assessments)	0	14.2093%	(c)	0	27.1340%	0	
21	PLUS Trans. Related General Advertising Expense	0	14.2093%	(c)	0	27.1340%	0	
22	Total A&G [line 18 plus (19 thru 21)]	4,284,067			57,578		15,624	
23	Payroll Tax Expense	323,811	1.0213%	(a)	3,307	27.1340%	897	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	323,811	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	323,811	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

Shading denotes an input

Line No.	PTF Transmission Plant Allocation Factor	GROTON	Reference
1	PTF Transmission Investment	$ 2,051,470	Used RSI numbers
2	Total Transmission Investment	7,560,499	DPUC Report-Page 501
3	Percent Allocation (Line 1/Line 2)	27.1340%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	30,982	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)	30,982	
7	Total Wages and Salaries	4,429,679	DPUC Report-Page 507
8	Administrative and General Wages and Salaries	1,396,074	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)	3,033,605	
11	Percent Allocation (Line 6/Line 10)	1.0213%	
	Plant Allocation Factor		
12	Total Transmission Investment	7,560,499	Line 2
13	plus Transmission-Related General Plant (Line 2 of Wkst. 3)	77,952	Worksheet 3, Line 2
14	= Revised Numerator (Line 12 + Line 13)	7,638,451	
15	Total Plant in Service	53,756,659	DPUC Report-Page 502
16	Percent Allocation (Line 14 / Line 15)	14.2093%	

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

City of Groton, Dept. of Utilities

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)

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 17, 2010
Revenue Requirements for (year):	Calendar Year 2009
Customer:	Mohegan Tribal Utility 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	=	0	(a)	$ 322,101	(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)	$ 322,101	(j)

Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:	$ 322,101	(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)	$ 322,101	(l)=(k)+(b)+(g)-(h)

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

Vendor	Invoice #	Component	Amount	Transmission	Distribution		Common	Comments
					Other	Transformer		
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	
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	

Mohegan Tribal Utility Authority

Shading denotes an input

Line No.			Attachment F Reference Section:	MTUA	Reference
	I. INVESTMENT BASE				
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)	$862,193	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)			$1,832,159	
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)	$1,239	Worksheet 3, Line 24
13	Total Investment Base (Line 9 + 10 + 11 + 12)			$1,833,398	
	II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes		(A)	$146,672	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)	$57,740	Worksheet 4, Line 8
19	Payroll Tax Expense		(F)	$0	Worksheet 4, Line 23
20	Operation & Maintenance Expense		(G)	$9,915	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)			$322,101	

Mohegan Tribal Utility Authority
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	Line 13 - DPUC Report, page 201	0.10%	6.00%	0.01%	0.01%
PREFERRED STOCK	0		0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	6,000,000	Line 8	99.90%	8.00%	7.99%	7.99%
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 = (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) / 1,833,398) 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) / 1,833,398) + 0.00%)* 0.00% / (1 - 0.00%)

= 0.00%

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

	(PTF)	
INVESTMENT BASE	$ 1,833,398	From Worksheet 1
x Cost of Capital Rate	8.00%	
= Investment Return and Income Taxes	146,672	To Worksheet 1

Shading denotes an input

Line No.	Alloc	(1) Total F	(2) Wage/Plant ation actors	(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	1,939,006		1,939,006	44.4657%	862,193	
6	General Plant Accum.Depreciation	0	100.0000% (a)	0	44.4657%	0	
7	Total (line 5 + 6)			1,939,006		862,193	
	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					9,915	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)					9,915	
23						0.125	x 45 days / 360
24	Total (line 22 * line 23)					1,239	

Mohegan Tribal Utility Authority

Shading denotes an input

Line (No.		(1) 1) Total F	(2) Wage/Plant Allocation actors		(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	129,853	100.0000%		129,853	44.4657%	57,740	See Below
7	General Property Taxes	0	100.0000%	(a)	0	44.4657%	0	information not available
8	Total (line 6+7)				129,853		57,740	
	Transmission Operation and Maintenance							
9	Operation and Maintenance	22,297			22,297	44.4657%	9,915	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	22,297			22,297	44.4657%	9,915	
	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 12/31/2008	6,059,395	
Less Furniture & Fixtures	0	
Net Taxable Plant	6,059,395	
Applicable Mil Rate	21.43	
	129,853	To cell d6 above

Shading denotes an input

Line No.	PTF Transmission Plant Allocation Factor	MTUA	Reference
1	PTF Transmission Investment	$2,694,352	See Inventory Tab
2	Total Transmission Investment	$6,059,395	See Inventory Tab
3	Percent Allocation (Line 1/Line 2)	44.4657%	
	Transmission Wages and Salaries Allocation Fac	0	
4	Direct Transmission Wages and Salaries	$6,685	MTUA
5	Affiliated Company Transmission Wages and Salaries	$0	Worksheet 6
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	$6,685	
7	Total Wages and Salaries	$6,685	
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)	$6,685	
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

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		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)

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 17, 2010
Revenue Requirements for (year):	Calendar Year 2009
Customer:	Norwich Public Utilities
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	=	37,539	(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)		37,539	(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:	37,539	(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)	37,539	(l)=(k)+(b)+(g)-(h)

	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		
	-	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			

Norwich Public Utilities

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)	$1,656	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)		$377,048	
5	Accumulated Depreciation	(A)(1)(d)	$288,740	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)		$88,308	
10	Prepayments	(A)(1)(h)	$51	Worksheet 3, Line 16
11	Materials & Supplies	(A)(1)(i)	$3,737	Worksheet 3, Line 17
12	Cash Working Capital	(A)(1)(j)	$524	Worksheet 3, Line 24
13	Total Investment Base (Line 9 + 10 + 11 + 12)		$92,620	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	$7,400	Worksheet 2
15	Depreciation Expense	(B)	$15,929	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)	$9,950	Worksheet 4, Line 8
19	Payroll Tax Expense	(F)	$65	Worksheet 4, Line 23
20	Operation & Maintenance Expense	(G)	$1,140	Worksheet 4, Line 13
21	Administrative & General Expense	(H)	$3,055	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)		$37,539	

Norwich Public Utilities
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	$	3,135,155	DPUC Rpt. P. 201, line 18	0.10%	4.00%	0.00%	0.00%
PREFERRED STOCK				0.00%	0.00%	0.00%	0.00%
COMMON EQUITY		32,086,351	DPUC Rpt. P. 201, line 10	99.90%	8.00%	7.99%	7.99%
TOTAL INVESTMENT RETURN	$	35,221,506		100.00%		7.99%	7.99%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0799

(b) Federal Income Tax =

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

$$= \frac{\left(0.0799 + \left(0 + 0\right) / 92{,}620\right) \times 0.00\%}{\left(1 - 0.00\%\right)}$$

= 0.00%

(c) State Income Tax =

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

$$= \frac{\left(0.0799 + \left(0 + 0\right) / 92{,}620\right) + 0.00\%\right) * 0.00\%}{\left(1 - 0.00\%\right)}$$

= 0.00%

(a)+(b)+(c) **Cost of Capital Rate** = 0.0799000

		(PTF)	
INVESTMENT BASE	$	92,620	From Worksheet 1
x Cost of Capital Rate		7.99%	
= Investment Return and Income Taxes		7,400	To Worksheet 1

Norwich Public Utilities

Shading denotes an input

Line No.	Alloc	(1) Total F	(2) Wage/Plant ation actors	(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	$ 9,565,512	0.2369% (a)	22,661	7.3072%	1,656	DPUC Annual Rpt. p. 501
3	Total (line 1 + 2)			5,159,981		377,048	
4	Transmission Plant Held for Future Use	0		0	7.3072%	0	information not available
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	3,933,812		3,933,812	7.3072%	287,452	DPUC Annual Rpt. p. 508, line 31
6	General Plant Accum.Depreciation	7,440,517	0.2369% (a)	17,627	7.3072%	1,288	DPUC Annual Rpt. p. 508, line 33
7	Total (line 5 + 6)			3,951,439		288,740	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes	0	10.0384% (c)	0	7.3072%	0	Not applicable.
9	Accumulated Deferred Taxes	0	10.0384% (c)	0	7.3072%	0	Not applicable.
10	Total (line 8 + 9)			0		0	
11	Transmission loss on Reacquired Debt	0	10.0384% (c)	0	7.3072%	0	Not applicable.
	Other Regulatory Assets						
12	FAS 106	0	0.2369% (a)	0	7.3072%	0	Not applicable.
13	FAS 109	0	10.0384% (c)	0	7.3072%	0	Not applicable.
14	Other Regulatory Liabilities (254.DK)	0	10.0384% (c)	0	7.3072%	0	Not applicable.
15	Total (line 12 + 13 + 14)	0		0		0	
16	Transmission Prepayments	296,561	0.2369% (a)	703	7.3072%	51	DPUC Annual Rpt, p. 210, line 14
17	Transmission Materials and Supplies	509,512	10.0384%	51,147	7.3072%	3,737	DPUC Report page 200 Line 25
18	Cash Working Capital						
19	Operation & Maintenance Expense					1,140	Worksheet 4, Line 13
20	Administrative & General Expense					3,055	Worksheet 4, Line 22
21	Transmission Support Expense					0	Worksheet 1, Line 24
22	Subtotal (line 19 + 20 + 21)					4,195	
23						0.125	x 45 days / 360
24	Total (line 22 * line 23)					524	

Shading denotes an input

Line (No.		(1) 1) Total F	(2) Wage/Plant Allocation actors		(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Reference
	Depreciation Expense							
1	Transmission Depreciation	217,026			217,026	7.3072%	15,859	
2	General Depreciation	404,095	0.2369%	(a)	957	7.3072%	70	DPUC Annual Rpt. p. 508, line 3
3	Total (line 1+2)				217,983		15,929	
4	Amortization of Loss on Reacquired Debt	0	10.0384%	(c)	0	7.3072%	0	not applicable
5	Amortization of Investment Tax Credits	0	10.0384%	(c)	0	7.3072%	0	not applicable
	Property Taxes *							
6	Transmission Property Taxes	1,356,491	10.0384%		136,170	7.3072%	9,950	See Below
7	General Property Taxes	0	0.2369%	(a)	0	7.3072%	0	information not available
8	Total (line 6+7)				136,170		9,950	
	Transmission Operation and Maintenance							
9	Operation and Maintenance	36,418			36,418	7.3072%	2,661	DPUC Annual Rpt. P. 518, line 47
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	20,817			20,817	7.3072%	1,521	DPUC Annual Rpt. P. 518, line 32 & 37
13	O&M less lines 10, 11 & 12	15,601			36,418	7.3072%	1,140	
	Transmission Administrative and General							
14	Administrative and General	12,186,760						DPUC Annual Rpt. P. 520, line 18
15	less Property Insurance (#924)	131,919						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)]	12,054,841	0.2369%	(a)	28,558	7.3072%	2,087	
19	PLUS Property Insurance alloc. using Plant Allocator	131,919	10.0384%	(c)	13,243	7.3072%	968	
20	PLUS Regulatory Comm. Exp. (FERC Assessments)	0	10.0384%	(c)	0	7.3072%	0	Not applicable.
21	PLUS Trans. Related General Advertising Expense	0	10.0384%	(c)	0	7.3072%	0	Not applicable.
22	Total A&G [line 18 plus (19 thru 21)]	12,186,760			41,801		3,055	
	Payroll Tax Expense							
	Federal Unemployment	0	0.2369%	(a)	0	7.3072%	0	information not available
	FICA	373,120	0.2369%	(a)	884	7.3072%	65	information not available
	Medicare	0	0.2369%	(a)	0	7.3072%	0	information not available
	CT Unemployment	0	0.2369%	(a)	0	7.3072%	0	information not available
23		373,120	0.2369%	(a)	884	7.3072%	65	

(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 12/31/2009	51,402,622	DPUC Annual Rpt. P. 501, line 18
Less Furniture & Fixtures	1,366,074	DPUC Annual Rpt. P. 501, line 4
Net Taxable Plant	50,036,548	
Applicable Mill Rate	27.11	From Town
	1,356,491	Place in cell d6 above.

Norwich Public Utilities

Shading denotes an input

Line No.	PTF Transmission Plant Allocation Factor	NPU	Reference
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	$20,611	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)	$20,611	
7	Total Wages and Salaries	$11,386,329	DPUC Annual Rpt. P. 507, line 45
8	Administrative and General Wages and Salaries	$2,684,936	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)	$8,701,393	
11	Percent Allocation (Line 6/Line 10)	0.2369%	
	Plant Allocation Factor		
12	Total Transmission Investment	$5,137,320	DPUC Annual Rpt. P. 500
13	plus Transmission-Related General Plant	$22,661	Worksheet 3, Line 2
14	= Revised Numerator (Line 12 + Line 13)	$5,159,981	
15	Total Plant in Service	$51,402,622	DPUC Annual Rpt. P. 501
16	Percent Allocation (Line 14 / Line 15)	10.0384%	

Norwich Public Utilities

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.

			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)

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 17, 2010
Revenue Requirements for (year):	Calendar Year 2009
Customer:	Town of Wallingford, Electric Division
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	=	80,982	(a)	628,370	(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)		(379)	(d)	0	(i)
Sub Total - Sum (A through I) - J + K + (L through O)		80,603	(e)=(a)-(b)+(c)+(d)	628,370	(j)

Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:	708,973	(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)	708,973	(l)=(k)+(b)+(g)-(h)

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						
		0.4251001	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.	$ 20,000.00	$
Corner Bus Support	1	ea.	$ 13,000.00	$
115kV Switch Support Stand	2	ea.	$ 35,000.00	$
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

$ 396,325.00

Town of Wallingford, Electric Division

Shading denotes an input

Line No.		Attachment F Reference Section:	WALLINGFORD	Reference
	I. INVESTMENT BASE			
1	Transmission Plant	(A)(1)(a)	$6,282,177	Worksheet 3, Line 1
2	General Plant	(A)(1)(b)	$81,640	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)		$6,363,817	
5	Accumulated Depreciation	(A)(1)(d)	$2,508,704	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)		$3,855,113	
10	Prepayments	(A)(1)(h)	$0	Worksheet 3, Line 16
11	Materials & Supplies	(A)(1)(i)	$43,428	Worksheet 3, Line 17
12	Cash Working Capital	(A)(1)(j)	$9,254	Worksheet 3, Line 24
13	Total Investment Base (Line 9 + 10 + 11 + 12)		$3,907,795	

Line No.		Attachment F Reference Section:	WALLINGFORD	Reference
	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	$312,624	Worksheet 2
15	Depreciation Expense	(B)	$179,549	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)	$143,149	Worksheet 4, Line 8
19	Payroll Tax Expense	(F)	$0	Worksheet 4, Line 23
20	Operation & Maintenance Expense	(G)	$42,729	Worksheet 4, Line 13
21	Administrative & General Expense	(H)	$31,301	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)	($379)	
28	Transmission Rents Received from Electric Property	(O)	$0	
29	Total Revenue Requirements (Line 14 thru 28)		$708,973	

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

Shading denotes an input

		CAPITALIZATION 12/31/2009		CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	0	Line 18 - DPUC Report, page 201	0.00%	6.00%	0.00%	0.00%
PREFERRED STOCK		0		0.00%	0.00%	0.00%	0.00%
COMMON EQUITY		56,418,931	Line 10 - DPUC Report, Page 201	100.00%	8.00%	8.00%	8.00%
TOTAL INVESTMENT RETURN	$	56,418,931		100.00%		8.00%	8.00%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0800

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

= $\dfrac{(0.0800 + (0 + 0) / 3{,}907{,}795) \times 0.00\%)}{(1 - 0.00\%)}$

= 0.00%

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

= $\dfrac{(0.0800 + (0 + 0) / 3{,}907{,}795) + 0.00\%)^{*} \ 0.00\%}{(1 - 0.00\%)}$

= 0.00%

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

		(PTF)	
INVESTMENT BASE	$	3,907,795	From Worksheet 1
x Cost of Capital Rate		8.00%	
= Investment Return and Income Taxes		312,624	To Worksheet 1

Shading denotes an input

Line Alloc No.		(1) Total F	(2) Wage/Plant ation actors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Reference
	Transmission Plant						
1	Transmission Plant	$ 8,925,973		8,925,973		6,282,177	DPUC Annual Rpt. p. 501, line 22
2	General Plant	$ 9,089,229	1.2762% (a)	115,997	70.3809%	81,640	DPUC Annual Rpt. p. 502, line 14
3	Total (line 1 + 2)			9,041,970		6,363,817	
4	Transmission Plant Held for Future Use	0		0	70.3809%	0	
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	3,304,964		3,304,964	70.3809%	2,452,767	DPUC Annual Rpt. p. 508, line 31
6	General Plant Accum.Depreciation	6,227,732	1.2762% (a)	79,478	70.3809%	55,937	DPUC Annual Rpt. p. 508, line 33
7	Total (line 5 + 6)			3,384,442		2,508,704	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes	0	9.5540% (c)	0	70.3809%	0	not applicable
9	Accumulated Deferred Taxes	0	9.5540% (c)	0	70.3809%	0	not applicable
10	Total (line 8 + 9)			0		0	
11	Transmission loss on Reacquired Debt	0	9.5540% (c)	0	70.3809%	0	not applicable
	Other Regulatory Assets						
12	FAS 106	0	1.2762% (a)	0	70.3809%	0	not applicable
13	FAS 109	0	9.5540% (c)	0	70.3809%	0	not applicable
14	Other Regulatory Liabilities (254.DK)	0	9.5540% (c)	0	70.3809%	0	not applicable
15	Total (line 12 + 13 + 14)	0		0		0	
16	Transmission Prepayments	0	1.2762% (a)	0	70.3809%	0	Assumed none
17	Transmission Materials and Supplies	645,848	9.5540%	61,704	70.3809%	43,428	DPUC Report page 200 Line 25
18	Cash Working Capital						
19	Operation & Maintenance Expense					42,729	Worksheet 4, Line 13
20	Administrative & General Expense					31,301	Worksheet 4, Line 22
21	Transmission Support Expense					0	Worksheet 1, Line 24
22	Subtotal (line 19 + 20 + 21)					74,030	
23						0.125	x 45 days / 360
24	Total (line 22 * line 23)					9,254	

Town of Wallingford, Electric Division

Shading denotes an input

Line No.		(1) Total Factors	(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	70.3809%	176,858	25 Year Depreciation
2	General Depreciation	299,673	1.2762% (a)	3,824	70.3809%	2,691	DPUC Annual Rpt. p. 508, line 3
3	Total (line 1+2)			255,111		179,549	
4	Amortization of Loss on Reacquired Debt	0	9.5540% (c)	0	70.3809%	0	not applicable
5	Amortization of Investment Tax Credits	0	9.5540% (c)	0	70.3809%	0	not applicable
	Property Taxes *						
6	Transmission Property Taxes	2,128,865	9.5540%	203,392	70.3809%	143,149	See Below
7	General Property Taxes	0	1.2762% (a)	0	70.3809%	0	information not available
8	Total (line 6+7)			203,392		143,149	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	60,711		60,711	70.3809%	42,729	DPUC Annual Rpt. p. 518, line 47
10	Transmission of Electricity by Others - #565	0		0	70.3809%	0	information not available
11	Load Dispatching - #561	0		0	70.3809%	0	information not available
12	**Station Expenses & Rents - #562 / #567	0		0	70.3809%	0	information not available
13	O&M less lines 10, 11 & 12	60,711		60,711	70.3809%	42,729	
	Transmission Administrative and General						
14	Administrative and General	3,190,003					DPUC Annual Rpt. p. 520, line 18
15	less Property Insurance (#924)	45,444					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)]	3,144,559	1.2762% (a)	40,131	70.3809%	28,245	
19	**PLUS** Property Insurance alloc. using Plant Allocator	45,444	9.5540% (c)	4,342	70.3809%	3,056	
20	**PLUS** Regulatory Comm. Exp. (FERC Assessments)	0	9.5540% (c)	0	70.3809%	0	not applicable
21	**PLUS** Trans. Related General Advertising Expense	0	9.5540% (c)	0	70.3809%	0	not applicable
22	Total A&G [line 18 plus (19 thru 21)]	3,190,003		44,473		31,301	
	Payroll Tax Expense						
	Federal Unemployment	0	1.2762% (a)	0	70.3809%	0	information not available
	FICA	0	1.2762% (a)	0	70.3809%	0	information not available
	Medicare	0	1.2762% (a)	0	70.3809%	0	information not available
	CT Unemployment	0	1.2762% (a)	0	70.3809%	0	information not available
23		0	1.2762% (a)	0	70.3809%	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 12/31/2008	94,640,690	DPUC Report Page 502 Line18
Less Furniture & Fixtures	2,879,264	DPUC Report Page 502 Line4
Net Taxable Plant	91,761,426	
Applicable Mil Rate	23.20	
	2,128,865	To cell d6 above

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	$8,925,973	DPUC Page 501 line22
3	Percent Allocation (Line 1/Line 2)	70.3809%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	$44,724	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)	$44,724	
7	Total Wages and Salaries	$4,236,584	DPUC Annual Rpt. P. 507, line 44
8	Administrative and General Wages and Salaries	$732,213	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)	$3,504,371	
11	Percent Allocation (Line 6/Line 10)	1.2762%	
	Plant Allocation Factor		
12	Total Transmission Investment	$8,925,973	DPUC Page 501 line22
13	plus Transmission-Related General Plant	$115,997	Worksheet 3, Line 2
14	= Revised Numerator (Line 12 + Line 13)	$9,041,970	
15	Total Plant in Service	$94,640,690	DPUC Annual Rpt. P. 502, line 18
16	Percent Allocation (Line 14 / Line 15)	9.5540%	

Town of Wallingford, Electric Division

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

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)

Sheet: Input Panel

EFFECTIVE JUNE 1, 2010
ISO New England Inc.
Annual Transmission Revenue Requirements
Per FERC Electric Tariff No. 3, Section II - Attachment F

Shading denotes an input

Submitted on:	17-May-10
Revenue Requirements for (year):	Calendar Year 2009
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:	00-695-2881

	Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I =	$264,807	(a)	$129,062	(f)
Total of Attachment F - Section J - Support Revenue	$0	(b)	$0	(g)
Total of Attachment F - Section K - Support Expense	$44,203	(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)	$309,010	(e)=(a)-(b)+(c)+(d)	$129,062	(j)=(f)-(g)+(h)+(i)
Forecasted Transmission Revenue Requirements (per Appendix C to Attachment F Implementation Rule)	N/A		$0	(m) Worksheet 1a
Annual True-up (per Appendix C to Attachment F Implementation Rule)	$39,613	(k)	$18,845	(n) Worksheet 1c
Interest Charge on Annual True-up	$1,336	(l)	$636	(o) Worksheet 1c
Total	$349,959	(p) =(e)+(k)+(l)	$148,543	(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) — $498,502 (r) =(p)+(q)

Fitchburg Gas and Electric Light Company
Annual Revenue Requirements of PTF Facilities
for costs in 2009
PRE-1997

Shading denotes an input

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	FG&E	Total	Reference
1	Transmission Plant	(A)(1)(a)	1,244,079	1,244,079	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	65,051	65,051	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)		1,309,130	1,309,130	
5	Accumulated Depreciation	(A)(1)(d)	537,225	537,225	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	244,585	244,585	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)	55,635	55,635	Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		582,955	582,955	
10	Prepayments	(A)(1)(h)	48,286	48,286	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	11,308	11,308	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	20,245	20,245	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		662,794	662,794	

	II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	80,452	80,452	Worksheet 2
15	Depreciation Expense	(B)	53,260	53,260	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)	11,885	11,885	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	1,456	1,456	*Worksheet 4, line 17 column 5*
20	Operation & Maintenance Expense	(G)	35,576	35,576	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	82,178	82,178	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)	44,203	44,203	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)		309,010	309,010	

Fitchburg Gas and Electric Light Company

Annual Revenue Requirements
for costs in 2009
PRE-1997

Shading denotes an input

	CAPITALIZATION 12/31/09*	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 70,000,000	55.70%	6.99%	3.89%	
PREFERRED STOCK	1,760,737	1.40%	6.85%	0.10%	0.10%
COMMON EQUITY	53,919,637	42.90%	11.64%	4.99%	4.99%
TOTAL INVESTMENT RETURN	$ 125,680,374	100.00%		8.98%	5.09%

*See Workpaper 2

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0898

(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)

= (0.0509 +(0 + 0) / 662,794) x 0.34) / (1 - 0.34)

= 0.0262212

(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)

= (0.0509 +(0 + 0) / 662,794) + 0.0262212)* 0.065 / (1 - 0.065)

= 0.0053614

(a)+(b)+(c) **Cost of Capital Rate** = 0.1213826

	(PTF)	
INVESTMENT BASE	$ 662,794	From Worksheet 1
x Cost of Capital Rate	0.1213826	
= Investment Return and Income Taxes	80,452	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		1,244,079	Line 1, Worksheet 5
							Page 207.87g + (Page 201.3h + 201.6h - Total A/C 303 - Total A/C 310)*49.26% (d)
2	General Plant	5,012,945	9.4361% (a)	473,026	13.7521%	65,051	(includes common plant)
3	Total (line 1+2)			473,026		1,309,130	
4	Transmission Plant Held for Future Use	0		0	13.7521%	0	Page 214
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	3,726,713		3,726,713	13.7521%	512,501	Page 219.25b
							Page 219.27c (includes common allocated
6	General Plant Accum.Depreciation	1,905,309	9.4361% (a)	179,787	13.7521%	24,724	to electric)
7	Total (line 5+6)			3,906,500		537,225	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	(19,814,340)	9.0011% (c)	(1,783,509)	13.7521%	(245,270)	Page 273.8k + 275.2k + 277.3k, See Workpaper 3
9	Accumulated Deferred Taxes (190)	55,319	9.0011% (c)	4,979	13.7521%	685	Page 234.8c
10	Total (line 8+9)			(1,778,530)		(244,585)	
11	Transmission loss on Reacquired Debt	0	9.0011% (c)	0	13.7521%	0	Page 111.81c
	Other Regulatory Assets						
12	FAS 106	1,158,317	9.4361% (a)	109,300	13.7521%	15,031	Page 232.13f.
13	FAS 109	3,280,227	9.0011% (c)	295,257	13.7521%	40,604	Page 232.1f - 278.1e
14	Other Regulatory Liabilities (254.DK)	0	9.0011% (c)	0	13.7521%	0	
15	Total (line 12+13+14)	4,438,544		404,557		55,635	
16	Transmission Prepayments	3,720,992	9.4361% (a)	351,117	13.7521%	48,286	Page 111.57c *p.200.8.c/p.200.8.b
17	Transmission Materials and Supplies	82,231		82,231	13.7521%	11,308	Page 227.8c
18	Cash Working Capital						
19	Operation & Maintenance Expense					35,576	Worksheet 1, Line 20
20	Administrative & General Expense					82,178	Worksheet 1, Line 21
21	Transmission Support Expense					44,203	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					161,957	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					20,245	

(a) Worksheet 5 of 8, line 11
(b) Worksheet 5 of 8, line 3
(c) Worksheet 5 of 8, line 16
(d) 49.26% is FGE's gas and electric labor allocator used for allocating common plant. See Workpaper 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	370,809		370,809	13.7521%	50,994	Page 336.7b
2	General Depreciation	174,618	9.4361% (a)	16,477	13.7521%	2,266	Page 336.10b (includes common allocated to electric)
3	Total (line 1+2)			387,286		53,260	
4	Amortization of Loss on Reacquired Debt	0	9.0011% (c)	0	13.7521%	0	Page 117.64c
5	Amortization of Investment Tax Credits	0	9.0011% (c)	0	13.7521%	0	Page 266.8f
	Property Taxes						
6	Transmission Property Taxes	960,145	9.0011% (c)	86,424	13.7521%	11,885	Page 263i, lines 9 & 11 & 16
7	General Property Taxes	0	9.4361% (a)	0	13.7521%	0	Page 262-263
8	Total (line 6+7)			86,424		11,885	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	5,521,525		5,521,525	0.137521	759,326	Page 321.112b
10	Transmission of Electricity by Others - #565	5,135,650		5,135,650	0.137521	706,260	Page 321.96b
11	Load Dispatch & Scheduling - #561.0 to #561.4	127,177		127,177	0.137521	17,490	Page 321.84b
12	**Station Expenses & Rents - #562 / #567	0		0	0.137521	0	Page 321.85b & .90b
13	O&M less lines 10, 11 & 12	258,698		258,698	13.7521%	35,576	
	Transmission Administrative and General						
14	Administrative and General	6,511,861					Page 323.197b
15	*less Property Insurance (#924)*	*32,358*					*Page 323.185b*
16	*less Regulatory Commission Expenses (#928)*	*251,184*					*Page 323.189b*
17	*less General Advertising Expense (#930.1)*	*2,000*					*Page 323.191b*
18	Subtotal [line 14 minus (15 thru 17)]	6,226,319	9.4361% (a)	587,522	13.7521%	80,797	
19	***PLUS** Property Insurance alloc. using Plant Allocation*	*32,358*	*9.0011% (c)*	2,913	13.7521%	401	
20	***PLUS** Regulatory Comm. Exp. (FERC Assessments - Transmissic*	*7,128*		7,128	13.7521%	980	Page 351.6h
21	***PLUS** Trans. Related General Advertising Expense*	*0*	*9.0011% (c)*	0	13.7521%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*6,265,805*		*597,563*		*82,178*	
23	*Payroll Tax Expense*	*112,229*	*9.4361% (a)*	*10,590*	*13.7521%*	*1,456*	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	1,858		*Page 263.4i*
FICA	183,572		*Page 263.2i*
Medicare	0		
State Unemployment	9,552		*Page 263.6i*
MA Universal Health	0		*Page 263.8i*
Payroll Taxes Capitalized	(82,753)		*Page 263.15i*
Total	112,229	*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.		FG&E	FERC Form 1 Reference
	PTF Transmission Plant Allocation Factor	**FG&E**	
1	PTF Transmission Investment	1,244,079	See Workpaper 1
2	Total Transmission Investment	9,046,466	Page 207.58g
3	Percent Allocation (Line 1/Line 2)	13.7521%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	93,533	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)	93,533	
7	Total Wages and Salaries	1,022,290	Page 354.25b + Line 5
8	Administrative and General Wages and Salaries	31,062	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)	991,228	
11	Percent Allocation (Line 6/Line 10)	9.4361%	
	Plant Allocation Factor		
12	Total Transmission Investment	9,046,466	Page 207.53g
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	473,026	*Worksheet 3, Line 2, col.(3)*
14	*= Revised Numerator (Line 12 + Line 13)*	9,519,492	
15	Total Plant in Service	105,759,250	Page 207.95g + ((Page 201.3h + 201.6h - Total A/C 303 - Total A/C 310)*.4926) (a)
16	Percent Allocation (Line 14 / Line 15)	9.0011%	

(a) 49.26% 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	

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	2,215	0	2,215
	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	13,298	0	13,298
	Comerford 115 kV Substation				
	345 kV Sandy-Tewksbury 337 line				
	345 kV Tewksbury-Woburn 338 line				
	115 kV Tewksbury - Woburn M139 line				
	115 kV Tewksbury - Woburn N140 line				
	Moore 115 kV Substation				
	HQ Phase II - AC in MA	0	28,690	0	28,690
	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	44,203	0	44,203

Amount by which Support Expense exceeds Support Reven 44,203
(To Worksheet 3, Line 21, Column 5)

Sheet: Worksheet 8

Summary of Fitchburg Gas and Electric Light Company System
Monthly Coincident Peaks for 2009
(Megawatts)
PRE-1997

Shading denotes an input

		JAN '09	FEB '09	MAR '09	APR '09	MAY '09	JUN '09	JUL '09	AUG '09	SEP '09	OCT '09	NOV '09	DEC '09
	Day	15	5	2	6	21	25	29	21	23	28	23	17
	Hour	18:00	19:00	19:00	11:00	16:00	17:00	14:00	15:00	20:00	19:00	18:00	19:00
FG&E		79	78	71	68	67	68	82	87	68	68	69	79

Annual FG&E System Average 12 CP Load **74**

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

Fitchburg Gas and Electric Light Company
Annual Revenue Requirements of PTF Faciliti
for costs in 2009
POST-1996

Shading denotes an input

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	Post-1996	Post-2003	Total	Reference
1	Transmission Plant	(A)(1)(a)	607,877	489,927		Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	31,785	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)		639,662	489,927		
5	Accumulated Depreciation	(A)(1)(d)	262,497	211,564 (1)		Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	119,508	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)	27,184	n/a		Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		284,841	207,427		
10	Prepayments	(A)(1)(h)	23,593	n/a		Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	5,526	n/a		Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	7,192	n/a		Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		321,152	207,427		

Line No.	II. REVENUE REQUIREMENTS	Attachment F Reference	Post-1996	Post-2003	Total	Reference
14	Investment Return and Income Taxes	(A)	38,982	0 (3)	38,982	Worksheet 2, Worksheet 2a
15	Depreciation Expense	(B)	26,024		26,024	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)	5,807		5,807	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	712		712	*Worksheet 4, line 17 column 5*
20	Operation & Maintenance Expense	(G)	17,383		17,383	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	40,154		40,154	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)		129,062	0	129,062	

(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.		I. FORECASTED TRANSMISSION REVENUE REQUIREMENTS	Period	Attachment F Reference *Section:*	FG&E	Reference
1		Forecasted Transmission Plant Additions	2010	Appendix C	-	Workpaper 1, Page 7
2		Carrying Charge Factor		Appendix C	21.23%	
3		Total Forecasted Revenue Requirements (Lines 1*2)			$0	
	II.	CARRYING CHARGE FACTOR				
4		Investment Return and Income Taxes		(A)	$38,982	Worksheet 1, line 14
5		Depreciation Expense		(B)	$26,024	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)	$5,807	Worksheet 1, line 18
9		Payroll Tax Expense		(F)	$712	Worksheet 1, line 19
10		Operation & Maintenance Expense		(G)	$17,383	Worksheet 1, line 20
11		Administrative & General Expense		(H)	$40,154	Worksheet 1, line 21
12		Total Expenses (Lines 4 thru 11)			$129,062	
13		PTF Transmission Plant		(A)(1)(a)	$607,877	Worksheet 5, Line 1, Pre-2004 plus Post-2003
14		Carrying Charge Factor (Lines 12/13)			21.23%	

Sheet: Worksheet 1b

Fitchburg Gas and Electric Light Company
Transmission Revenue Requirements of PTF Facilities
2009 True-up
POST-2003

Line No.	I.	ANNUAL TRUE-UP PER ATTACHMENT F	Period	Attachment F Reference *Section:*	FG&E **Pre-97**	FG&E **Post 96**	Reference
	1	Transmission Revenue Requirements (as billed)	6/09 - 5/10		$ 269,397	$ 110,217	ATRR - Prior Year
	2	True-up 2009 Actual Annual RR			$ 309,010	$ 129,062	Voting Share (e), (j)
	3	Over/(Under) (Line 1 - Line 2)			$ (39,613)	$ (18,845)	
	4	Over/(Under) June 1, 2009 - May 31, 2010			$ (39,613)	$ (18,845)	

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

		Under / (Over)
PRE97	$	39,613
Post 1996	$	18,845

Initial Billing Period		PRE97 Balance		Post 1996 Balance	Monthly Interest Rate		PRE97 Interest		Post 1996 Interest
June 2009	$	39,613	$	18,845	0.28%	$	111	$	53
July 2009	$	39,724	$	18,898	0.28%	$	111	$	53
August 2009	$	39,724	$	18,898	0.28%	$	111	$	53
September 2009	$	39,724	$	18,898	0.27%	$	107	$	51
October 2009	$	40,053	$	19,055	0.28%	$	112	$	53
November 2009	$	40,053	$	19,055	0.27%	$	108	$	51
December 2009	$	40,053	$	19,055	0.28%	$	112	$	53
January 2010	$	40,386	$	19,213	0.28%	$	113	$	54
February 2010	$	40,386	$	19,213	0.28%	$	113	$	54
March 2010	$	40,386	$	19,213	0.28%	$	113	$	54
Apr-2010	$	40,725	$	19,374	0.27%	$	110	$	52
May-2010	$	40,725	$	19,374	0.28%	$	114	$	54
				Total Interest		$	1,336	$	636
				True-Up		$	39,613	$	18,845
				Total True-Up & Interest		**$**	**40,949**	**$**	**19,481**

Fitchburg Gas and Electric Light Company

Annual Revenue Requirements
for costs in 2009
POST-1996

Shading denotes an input

		CAPITALIZATION 12/31/09*	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	70,000,000	55.70%	6.99%	3.89%	
PREFERRED STOCK	$	1,760,737	1.40%	6.85%	0.10%	0.10%
COMMON EQUITY	$	53,919,637	42.90%	11.64%	4.99%	4.99%
TOTAL INVESTMENT RETURN	$	125,680,374	100.00%		8.98%	5.09%

*See Workpaper 2

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0898

(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)

= (0.0509 +(0 + 0) / 321,152) x 0.34) / (1 - 0.34)

= 0.0262212

(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)

= (0.0509 +(0 + 0) / 321,152) + 0.0262212)* 0.065 / (1 - 0.065)

= 0.0053614

(a)+(b)+(c) **Cost of Capital Rate** = 0.1213826

		(PTF)	
INVESTMENT BASE	$	321,152	From Worksheet 1, Line 13, Post-96
x Cost of Capital Rate		0.1213826	
= Investment Return and Income Taxes		38,982	To Worksheet 1

Sheet: Worksheet 3

Fitchburg Gas and Electric Light Company

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		607,877	Line 1, Worksheet 5
							Page 207.99g + (Page 201.3h + 201.6h - Total A/C 303 - Total A/C 310)*49.26% (d)
2	General Plant	5,012,945	9.4361% (a)	473,026	6.7195%	31,785	(includes common plant)
3	Total (line 1+2)			473,026		639,662	
4	Transmission Plant Held for Future Use	0		0	6.7195%	0	Page 214
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	3,726,713		3,726,713	6.7195%	250,416	Page 219.25b
							Page 219.28c (includes common allocated
6	General Plant Accum.Depreciation	1,905,309	9.4361% (a)	179,787	6.7195%	12,081	to electric)
7	Total (line 5+6)			3,906,500		262,497	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	(19,814,340)	9.0011% (c)	(1,783,509)	6.7195%	(119,843)	Page 273.8k + 275.2k + 277.3k, See Workpaper 3
9	Accumulated Deferred Taxes (190)	55,319	9.0011% (c)	4,979	6.7195%	335	Page 234.8c
10	Total (line 8+9)			(1,778,530)		(119,508)	
11	Transmission loss on Reacquired Debt	0	9.0011% (c)	0	6.7195%	0	Page 111.81c
	Other Regulatory Assets						
12	FAS 106	1,158,317	9.4361% (a)	109,300	6.7195%	7,344	Page 232.20f
13	FAS 109	3,280,227	9.0011% (c)	295,257	6.7195%	19,840	Page 232.1f - 278.1e
14	Other Regulatory Liabilities (254.DK)	0	9.0011% (c)	0	6.7195%	0	
15	Total (line 12+13+14)	4,438,544		404,557		27,184	
16	Transmission Prepayments	3,720,992	9.4361% (a)	351,117	6.7195%	23,593	Page 111.57c *p.200.8.c/p.200.8.b
17	Transmission Materials and Supplies	82,231		82,231	6.7195%	5,526	Page 227.8c
18	Cash Working Capital						
19	Operation & Maintenance Expense					17,383	Worksheet 1, Line 20
20	Administrative & General Expense					40,154	Worksheet 1, Line 21
21	Transmission Support Expense					0	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					57,537	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					7,192	

(a) Worksheet 5 of 8, line 11
(b) Worksheet 5 of 8, line 3
(c) Worksheet 5 of 8, line 16
(d) 49.26% is FGE's gas and electric labor allocator used for allocating common plant. See Workpaper 4.

Fitchburg Gas and Electric Light Company

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	370,809		370,809	6.7195%	24,917	Page 336.7b
2	General Depreciation	174,618	9.4361% (a)	16,477	6.7195%	1,107	Page 336.10b (includes common allocated to electric)
3	Total (line 1+2)			387,286		26,024	
4	Amortization of Loss on Reacquired Debt	0	9.0011% (c)	0	6.7195%	0	Page 117.64c
5	Amortization of Investment Tax Credits	0	9.0011% (c)	0	6.7195%	0	Page 266.8f
	Property Taxes						
6	Transmission Property Taxes	960,145	9.0011% (c)	86,424	6.7195%	5,807	Page 263i, lines 9 & 11 & 16
7	General Property Taxes	0	9.4361% (a)	0	6.7195%	0	Page 262-263
8	Total (line 6+7)			86,424		5,807	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	5,521,525		5,521,525	6.7195%	371,019	Page 321.112b
10	Transmission of Electricity by Others - #565	5,135,650		5,135,650	6.7195%	345,090	Page 321.96b
11	Load Dispatch & Scheduling - #561.0 to #561.4	127,177		127,177	6.7195%	8,546	Page 321.84b to 321.88b
12	**Station Expenses & Rents - #562 / #567	0		0	6.7195%	0	Page 321.93b & .98b
13	O&M less lines 10, 11 & 12	258,698		258,698	6.7195%	17,383	
	Transmission Administrative and General						
14	Administrative and General	6,511,861					Page 323.197b
15	*less Property Insurance (#924)*	*32,358*					*Page 323.185b*
16	*less Regulatory Commission Expenses (#928)*	*251,184*					*Page 323.189b*
17	*less General Advertising Expense (#930.1)*	*2,000*					*Page 323.191b*
18	Subtotal [line 14 minus (15 thru 17)]	6,226,319	9.4361% (a)	587,522	6.7195%	39,479	
19	***PLUS** Property Insurance alloc. using Plant Allocation*	*32,358*	*9.0011% (c)*	2,913	6.7195%	196	
20	***PLUS** Regulatory Comm. Exp. (FERC Assessments - Transmission)*	*7,128*		7,128	6.7195%	479	Page 351.6h
21	***PLUS** Trans. Related General Advertising Expense*	*0*	*9.0011% (c)*	0	6.7195%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*6,265,805*		*597,563*		*40,154*	
23	*Payroll Tax Expense*	*112,229*	*9.4361% (a)*	*10,590*	*6.7195%*	*712*	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	1,858		*Page 263.4i*
FICA	183,572		*Page 263.2i*
Medicare	0		
State Unemployment	9,552		*Page 263.6i*
MA Universal Health	0		*Page 263.8i*
Payroll Taxes Capitalized	(82,753)		*Page 263.15i*
Total	112,229	*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.		Post-1996	Post-2003	Total Post-96	FERC Form 1 Reference
	PTF Transmission Plant Allocation Factor				
1	PTF Transmission Investment	117,950	489,927	607,877	See Workpaper 1
2	Total Transmission Investment	9,046,466	9,046,466	9,046,466	Page 207.58g
3	Percent Allocation (Line 1/Line 2)	1.3038%	5.4157%	6.7195%	
	Transmission Wages and Salaries Allocation Factor				
4	Direct Transmission Wages and Salaries	93,533			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)	93,533			
7	Total Wages and Salaries	1,022,290			Page 354.28b + Line 5
8	Administrative and General Wages and Salaries	31,062			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)	991,228			
11	Percent Allocation (Line 6/Line 10)	9.4361%			
	Plant Allocation Factor				
12	Total Transmission Investment	9,046,466			Page 207.53g
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	473,026			*Worksheet 3, Line 2, col.(3)*
14	*= Revised Numerator (Line 12 + Line 13)*	9,519,492			
15	Total Plant in Service	105,759,250			Page 207.104g + ((Page 201.3h + 201.6h - Total A/C 303 - Total A/C 310)*.4926) (a)
16	Percent Allocation (Line 14 / Line 15)	9.0011%			

(a) 49.26% 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 Revenues 0
(To Worksheet 3, Line 21, Column 5)

Sheet: Worksheet 8

Summary of Fitchburg Gas and Electric Light Company System
Monthly Coincident Peaks for 2009
(Megawatts)
POST-1996

Shading denotes an input

	JAN '09	FEB '09	MAR '09	APR '09	MAY '09	JUN '09	JUL '09	AUG '09	SEP '09	OCT '09	NOV '09	DEC '09
Day	15	5	2	6	21	25	29	21	23	28	23	17
Hour	18:00	19:00	19:00	11:00	16:00	17:00	14:00	15:00	20:00	19:00	18:00	19:00
FG&E	79	78	71	68	67	68	82	87	68	68	69	79

Annual FG&E System Average 12 CP Load **74**

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
<u>Land</u>									
1977	Cost of Land purchased from New England Power Co.		6,663.35	5	0	0	0	0	6663.35
Oct-78	Acquisition Costs for land at Flagg Pond Sub		817.70	5	0	0	0	0	817.7
<u>Improvements</u>									
Aug-65	Structures and Improvements		24,143.99	5	0	0	0	0	24143.99
Nov-77	Purchased from NEP on 6/1/77, Tx Portion S/N's 6994207 & 34891		443,407.08	4	0	0	0	443407.08	0
	Purchased from NEP on 6/1/77, 115 kV Portion		414,449.05	1	414449.05	0	0	0	0
	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 install		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

					PTF	Non-PTF	PTF XMFR	Non-PTF XMFR	Common
Date	Description	In Service	Value	Classification	1	2	3	4	5
Land									
Apr-94	Fused Disconnect	1977	(505.26)	5	0	0	0	0	-505.26
May-94	Replace Fused Disconnect		434.21	5	0	0	0	0	434.21
Sep-94	Install & purch EM-GRO Air Compressor		1,273.97	5	0	0	0	0	1273.97
Sep-94	Install Deadend Structure 3-arrestors & 6-bushings		30,233.66	5	0	0	0	0	30233.66
Sep-95	Construct 115 Kv facilities & connect spare transformer		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 Services	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 Antenna	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 Invoices	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 install	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

Date	Description	In Service	Value	Classification	PTF 1	Non-PTF 2	PTF XMFR 3	Non-PTF XMFR 4	Common 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 Auto		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 installed		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 Breaker		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 House		95,020.03	5	0	0	0	0	95020.03
Mar-03	Installation of cable trench for new Control House		113,635.68	5	0	0	0	0	113635.68
Nov-05	Retire UV Relay Installed	Dec-99	(605.13)	2	0	-605.13	0	0	0
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 chgs	1997	(3,799.62)	2	0	-3799.62	0	0	0
Total POST-96 PTF			$550,588.20		$0.00	$322,818.22	$0.00	$0.00	$227,769.98
Jan-04	Replace 69Kv Pin & Cap Insulator		529.89	2	0	529.89	0	0	0
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
Total Post-03 PTF			$2,134,735.61		$489,926.84	$654,069.26	$0.00	$990,739.51	$0.00
PTF	1,692,316.54		$ 5,944,865.18		$ 1,692,316.54	$ 1,575,656.39	$ -	###########	$ 308,275.04
non-PTF	1,575,656.39								
					51.78%	48.22%			
PTF Ratio	0.5178								

Pre-97 PTF	1,202,390	POST-96 PTF	-
XFRM Pre-97 PTF	-	XFRM POST-96 PTF	-
COMMON Pre-97 PTF	41,689	COMMON POST-96 PTF	117,950
Total Pre-97PTF	1,244,079	Total POST-96 PTF	117,950
POST-03 PTF	489,927		
XFRM POST-03 PTF	-		
COMMON POST-03 PTF	-		
Total POST-03 PTF	489,927		

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	

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 Company
2010 Estimated PTF Plant Additions

Date	Description	Value	Classification	PTF 1	Non-PTF 2	PTF XMFR 3	Non-PTF XMFR 4	Common 5
Post 2005								
Est. 2010				$0	0	0	0	0
Total		$0		$0	$0	$0	$0	$0
PTF Ratio (See page 3)								51.78%
PTF Estimated Additions								$0

WORKPAPER 2

Fitchburg Gas and Electric Light Company

2009 Cost of Capital

	Amount Outstanding 12/31/09	*C.O.C.*	*Weight*	*Weighted Cost of Capital*
Common Stock Equity	$53,919,637	11.64%	42.90%	4.99%
Preferred Stock	1,760,737	6.85%	1.40%	0.10%
Long Term Debt (include. due in 1 yr.)	70,000,000	6.99%	55.70%	3.89%
Total	$125,680,374			8.98%

Common Equity

Common Stock	$22,627,257
Retained Earnings	11,799,463
Capital Stock Expense	(1,507,083)
Misc. Paid in Capital	21,000,000
Total	$53,919,637

Preferred Stock $100 Par

Series		*Amount Outstanding 12/31/09*	*Annual Issuance Expense*	*Annual Dividend Expense*	*Total Annual Cost*	*Effective Cost %*
5.125%		$810,200	$232	$41,788	$42,020	5.19%
8.00%		979,100	105	78,434	78,539	8.02%
		$1,789,300	$338	$120,222	$120,560	6.74%
Less: Capital Stock Expense	5.125%	$9,098				
	8.00%	19,466				
	Subtotal	$28,563				
Total		1,760,737				6.85%

Long Term Debt

Series		*Amount Outstanding 12/31/09*	*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

				2009	
1.	Account 281	Accumulated Deferred Income Taxes - Accelerated Amortization Property	$	-	FF1, Page 273.8k
2.	Account 282	Accumulated Deferred Income Taxes - Other Property	$	13,305,526	FF1, Page 275.2k
3.	Account 283	Account 283 - Electric	$	(1,033,548)	FF1, Page 277.3k
4.	Account 283	Less FAS 106 OPEB	$	(1,191,469)	
5.	Account 283	Less FAS 158	$	(6,350,893)	
			$	19,814,340	Worksheet 3, Line 8

Detail for Lines 4 and 5. Source: accounting records.	Electric		Gas		Total	
Def FIT FAS 158 SERP	$	(273,530)	$	(274,313)	$	(547,842)
Def SIT FAS 158 SERP	$	(74,737)	$	(74,951)	$	(149,687)
Def FIT FAS 158 Pension	$	(3,145,329)	$	(3,213,252)	$	(6,358,581)
Def SIT FAS 158 Pension	$	(698,890)	$	(712,601)	$	(1,411,491)
Def FIT FAS 158 PBOP	$	(1,754,094)	$	(1,780,833)	$	(3,534,927)
Def SIT FAS 158 PBOP	$	(404,313)	$	(409,366)	$	(813,680)
Total FAS 158	$	(6,350,893)	$	(6,465,316)	$	(12,816,209)
Def FIT FAS 106 OPEB	$	(1,012,933)	$	(915,583)	$	(1,928,516)
Def SIT FAS 106 OPEB	$	(178,536)	$	(215,782)	$	(394,318)
Total FAS 106 OPEB	$	(1,191,469)	$	(1,131,365)	$	(2,322,834)

Workpaper 4
Fitchburg Gas and Electric Light Company
Labor Allocator
2008 percentages applicable to 2009 costs

		Gas	Electric	Total
Salaries & Wages - Operation & Maintenance				
	Production - Maint	$ 39,507		$ 39,507
	Production - Oper	198,367		198,367
	Transmission - Maint		20,505	20,505
	Transmission - Oper	92,867	63,170	156,037
	Distribution - Maint	152,468	284,069	436,538
	Distribution - Oper	666,690	569,747	1,236,437
	Customer Accounting	16,606	89,365	105,971
	Admin & General	299	386	686
	Total - O&M Direct Labor	**1,166,805**	**1,027,242**	**2,194,046**
Construction				
	Direct Payroll	253,465	474,996	728,460
	Overhead Payroll	327,889	194,833	522,722
	Total - Construction Direct Labor	**581,354**	**669,829**	**1,251,183**
	Total Direct Labor	**$ 1,748,159**	**$ 1,697,071**	**$ 3,445,229**
	Labor Allocator	**50.74%**	**49.26%**	**100.00%**

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

			2009	
Account 281	Accumulated Deferred Income Taxes - Accelerated Amortization Property	$	-	FF1, Page 273.8k
Account 282	Accumulated Deferred Income Taxes - Other Property	$	13,305,526	FF1, Page 275.2k
	Total Accounts 281, 282	$	13,305,526	
	Plant Allocation Factor		9.7998%	Worksheet 5, Line 16
	Transmission Allocated (Total Accounts 281, 282 * Plant Allocation Factor)	$	1,303,915	
	Post-2003 PTF Transmission Plant Allocation Factor		5.4402%	Worksheet 5, Line 3 - Column 2
	Post-2003 PTF Accumulated Deferred Income Tax	$	70,936	Worksheet 1, Line 6

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

			2009	
20-20-13-00-565-75-00	BECO HQII - TRANSMISSION	$	2,215	Worksheet 7, BECo HQ Phase II - AC in MA
20-20-13-565-76-00-01	NEP HQII - TRANSMISSION	$	28,690	Worksheet 7, NEP HQ Phase II - AC in MA

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

2009 ACTUAL CHESTER SVC COSTS $ 3,063,350

SUPPORTER	SUPPORTER SHARE		
Fitchburg Gas and Electric Light Company	0.4341%	$ 13,298	(1)

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

RTO-NE Regional Transmission Service
FPL-NED'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, 2010 through May 31, 2011

Revenue Requirements for Test Year:	2009
Customer:	FPL - NED
Customer's NABs Number:	
Name of Participant responsible for customer's billing:	FPL NED
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	3,210,871	Pre-97 WS1, ln 14-22	5,077,690	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	692,146	Pre-97 WS1, ln 24	0	Post-96 WS1, ln 24
Total of Attachment F - Section (L through O)	4	(559)	Pre-97 WS1, ln 27	(899)	Post-96 WS1, ln 27
Sub Total - Sum (A through I) - J + K + (L through O)	5	3,902,457	Sum of above	5,076,792	Sum of above
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	6	N/A		$408,014	Post-96 WS8, ln. 3
Annual True-up (per Attachment C to Attachment F Implementation Rule)	7	$ (3,540,937)	TU WS4, line 16	$ 3,631,932	TU WS4, line 16
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)	8	$ 361,521	lns. 5+6+7	$9,116,738	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) **$9,478,259** Sum of lines 8 Pre-97 & Post-96 above

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

Shading denotes an input

Line No.		Attachment F Reference	FPL NED	Reference
	I. INVESTMENT BASE	Section:		
1	Transmission Plant	(A)(1)(a)	19,303,754	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)		19,303,754	
5	Accumulated Depreciation	(A)(1)(d)	6,724,974	Pre-97 WS3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	1,000,912	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)		11,577,868	
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)	191,355	Pre-97 WS3, line 24 column 5
13	Total Investment Base (Line 9+10+11+12)		11,769,223	
	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	1,612,135	Pre-97 WS2
15	Depreciation Expense	(B)	650,426	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)	104,369	Pre-97 WS4, line 9 column 5
19	Payroll Tax Expense	(F)	5,249	Pre-97 WS4, line 33 column 5
20	Operation & Maintenance Expense	(G)	706,288	Pre-97 WS4, line 14 column 5
21	Administrative & General Expense	(H)	132,403	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)	692,146	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)	(559)	Pre-97 WS8, line 5 column b
28	Transmission Rents Received from Electric Property	(O)	0	NA
29	Total Pre-'97 Revenue Requirements (Line 14 thru 28)		**3,902,457**	

NOTES:
1. All amounts represent FPL-NED's (or its affilitiates) 88.22889% ownership share in the Seabrook Transmission Substation.

RTO-NE Regional Transmission Service
FPL-NED'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 12/31/06	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 5,846,012,612	40.93%	5.20%	2.13%	
PREFERRED STOCK	0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	8,435,841,408	59.07%	11.64%	6.88%	6.88%
TOTAL INVESTMENT RETURN	$ 14,281,854,020	100.00%		9.01%	6.88%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0901

(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)

= (0.0688 +(0 + 0) / 11,769,223) x 0.35) / (1 - 0.35)

= 0.0370462

(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)

= (0.0688 +(0 + 0) / 11,769,223) + 0.0370462)* 0.085 / (1 - 0.085)

= 0.0098327

(a)+(b)+(c) Cost of Capital Rate = 0.1369789

	(PTF)	
INVESTMENT BASE	$ 11,769,223	From Pre-97 WS1, line 13
x Cost of Capital Rate	0.1369789	
= Investment Return and Income Taxes	1,612,135	To Pre-97 WS1, Line 14

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

Shading denotes an input

Line No.		(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) Pre-Post PTF Allocation Factor	(5) = (3)*(4) PTF Allocated	Reference for col (1)
	Transmission Plant						
1	Transmission Plant (Pre-'97 PTF)	19,303,754	Directly Assigned	19,303,754	Directly Assigned	19,303,754	Pre-97 WS 5, line 1
2	General Plant	0		0		0	
3	Total (line 1+2)					19,303,754	
4	Transmission Plant Held for Future Use	0		0		0	
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	6,724,974	Directly Assigned	6,724,974	Directly Assigned	6,724,974	Plant Data Support 5
6	General Plant Accum. Depreciation	0		0		0	
7	Total (line 5+6)					6,724,974	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	1,000,912	100.0000%	1,000,912	Directly Assigned (a)	1,000,912	Plant Data Support 5
9	Accumulated Deferred Taxes (190)	0		0		0	
10	Total (line 8+9)					1,000,912	
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					706,288	Pre-97 WS 1, Line 20
20	Administrative & General Expense					132,403	Pre-97 WS 1, Line 21
21	Transmission Support Expense					692,146	Pre-97 WS 7
22	Subtotal (line 19+20+21)					1,530,837	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					191,355	

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.

References:
(a) Worksheet 5, line 3 (Pre-97 PTF/HTF Transmission Plant Allocation Factor)

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

Shading denotes an input

Line No.		(1) Total	(2) Wage / 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	650,426	Directly Assigned	650,426	Directly Assigned	650,426	Data Support
2	General Depreciation	0		0		0	
3	Total (line 1+2)					650,426	
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	317,799	100% (c)	317,799	32.8412% (a)	104,369	FPL Form 1
8	General Property Taxes	0		0		0	
9	Total (line 7+8)	317,799				104,369	
	Transmission Operation and Maintenance						
10	Operation and Maintenance (Directly Assigned to Transmission; Allocated to PTF)	2,150,617	Directly Assigned	2,150,617	32.8412% (a)	706,288	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	2,150,617				706,288	
	Transmission Administrative and General						
20	Administrative and General (FPL-NED costs; see note 2)	403,161					FPL Form 1
21	less Property Insurance (#924) (FPL-NED costs; see note 2)	13,398					FPL Form 1
22	less Regulatory Commission Expenses (#928) (FPL-NED costs; see note 2)	160,343					FPL Form 1
23	less General Advertising Expense (#930.1)	0					
24	Subtotal [line 20 minus (21 thru 23)]	229,420	100% (b)	229,420	32.8412% (a)	75,344	
26	PLUS Property Insurance (FPL-NED costs; see note 2)	13,398	100% (c)	13,398	32.8412% (a)	4,400	FPL Form 1
28	PLUS Regulatory Comm. Exp.: FERC Assessments (FPL-NED costs; see note 2)	160,343	100% (c)	160,343	32.8412% (a)	52,659	FPL Form 1
29	PLUS Trans. Related General Advertising Expense	0		0		0	
30	Total A&G [line 20 plus (26 thru 29)]	403,161				132,403	
33	Payroll Tax Expense - Transmission Related Total	15,984	100% (b)	15,984	32.8412% (a)	5,249	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.
2. FPL-NED'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 FPL-NED)
(c) Worksheet 5, line 19 (Transmission Plant Allocation Factor applicable to FPL-NED.)

RTO-NE Regional Transmission Service
FPL-NED'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.		FPL NED	Reference
	PTF/HTF Transmission Plant Allocation Factor		
1	PTF Transmission Investment (Pre 1997)	19,303,754	Plant Data Support or Form 1
2	Total Transmission Investment	58,779,035	Plant Data Support or Form 1
3	Percent Allocation (Line 1/Line 2)	32.8412%	Line 1 / line 2
	PTF/HTF Transmission Plant Allocation Factor		
4	PTF Transmission Investment (Post-1996)	31,000,233	Plant Data Support or Form 1
5	Total Transmission Investment	58,779,035	Plant Data Support or Form 1
6	Percent Allocation (Line 4/Line 5)	52.7403%	Line 4 / line 5
	Transmission Wages and Salaries Allocation Factor		
7	Direct Transmission Wages and Salaries	147,777	Form 1
8	Affiliated Company Transmission Wages and Salaries	0	Form 1
9	Total Transmission Wages and Salaries (Line 7 + Line 8)	147,777	Sum Lines 7 + 8
10	Total Wages and Salaries	181,414	Form 1
11	Administrative and General Wages and Salaries	33,637	Form 1
12	Affiliated Company Wages and Salaries less A&G	0	Form 1
13	Total Wages and Salaries net of A&G (Line 10 - 11 + 12)	147,777	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	58,779,035	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)	58,779,035	Sum Lines 15 + 16
18	Total Plant in Service	58,779,035	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	19,303,754	Plant Data Support or Form 1
21	PTF POST 1996 Transmission Investment	31,000,233	Plant Data Support or Form 1
22	Total PTF Transmission Plant (Line 20+21)	50,303,987	Sum Lines 20 + 21
23	Percentage PTF PRE 1997 Transmission Investment (Line 20 / 22)	38.3742%	Line 20 / Line 22
24	Percentage PTF POST 1996 Transmission Investment (Line 21 / 22)	61.6258%	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
FPL-NED's PTF Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO-NE Open Access Transmission Tariff
ROE BASED ON REHEARING ORDER BASE ROE SET AT 10.4% + 0.74 Bond Yield Adjustment + 0.5 RTO Adder
Pre-'97 ATRR

Affiliated Company Wages and Salaries

Shading denotes an input

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

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

RTO-NE Regional Transmission Service
FPL-NED'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		FPL NED	
Participant	PTF Supporting Facilities	FERC Form 1	Revenues (a)	Expenses (b)
NEP	345 kV NH/MA border - Tewksbury 394 line			See note
NU	345 kV 363, 369 and 394 Seabrook Lines			See note
		Total =	0	692,146

Ties to FPL-NED Form 1

Amount by which Support Expense exceeds Support Revenues 692,146
(To Worksheet 3, Line 21, Column 5)

Note: Total amount represent FPL's 88.22889% ownership share in the Seabrook Substation of the Seabrook Transmission Support Agreement as recorded

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

Short-Term Revenues Received Under ISO-NE Tariff

Line No.	(a) Revenue Source	(b) Total Amount	Reference
1	TOUT Revenues	$1,458	ISO-NE
2	Post-96 PTF Plant Allocator	61.6%	Post-96 WS5, line 24
3	Pre-97 PTF Plant Allocator	38.4%	Post-96 WS5, line 23
4	Post-96 Revenues	$899	Line 1 x Line 2
5	Pre-97 Revenues	$559	Line 1 x Line 3

RTO-NE Regional Transmission Service
FPL-NED'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 Section:	FPL NED	Reference
	I. INVESTMENT BASE			
1	Transmission Plant	(A)(1)(a)	31,000,233	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)		31,000,233	
5	Accumulated Depreciation	(A)(1)(d)	1,334,532	Post-96 WS 3, line 8, column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	6,170,136	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)		23,495,565	
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)	168,359	Post-96 WS 3, line 27, column 5
13	Total Investment Base (Line 9+10+11+12)		23,663,924	
	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes (Post-'96 / Pre-'04 Investments)	(A)	3,241,458	Post-96 WS2
15	Incentive Investment Return and Income Taxes (Eligible Investments)	(A)	0	Post-96 WS2A
16	Depreciation Expense	(B)	313,324	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)	167,608	Post-96 WS4, line 9 column 5
20	Payroll Tax Expense	(F)	8,430	Post-96 WS4, line 32 column 5
21	Operation & Maintenance Expense	(G)	1,134,242	Post-96 WS4, line 14 column 5
22	Administrative & General Expense	(H)	212,628	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)	(899)	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)		**5,076,792**	

NOTES:
1. All amounts represent FPL-NED's 88.22889% ownership share in the Seabrook Transmission Substation.

RTO-NE Regional Transmission Service
FPL-NED'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 12/31/06	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 5,846,012,612	40.93%	5.20%	2.13%	
PREFERRED STOCK	0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	8,435,841,408	59.07%	11.64%	6.88%	6.88%
TOTAL INVESTMENT RETURN	$ 14,281,854,020	100.00%		9.01%	6.88%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0901

(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)

= (0.0688 +(0 + 0) / 2,030,118) x 0.35) / (1 - 0.35)

= 0.0370462

(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)

= (0.0688 +(0 + 0) / 2,030,118) + 0.0370462)* 0.085 / (1 - 0.085)

= 0.0098327

(a)+(b)+(c) Cost of Capital Rate = 0.1369789

	(PTF)	
INVESTMENT BASE	$ 23,663,924	From Post-96 WS 1, line 13
x Cost of Capital Rate	0.1369789	
= Investment Return and Income Taxes	3,241,458	To Post-96 WS 1, Line 14

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

RTO-NE Regional Transmission Service
FPL-NED'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	$ 5,846,012,612	40.93%	5.20%	NA	NA
PREFERRED STOCK	0	0.00%	0.00%	NA	NA
COMMON EQUITY	8,435,841,408	59.07%	1.00%	0.59%	0.59%
TOTAL INVESTMENT RETURN	$ 14,281,854,020	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

FPL-NED'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)	31,000,233	Directly Assigned	31,000,233	Directly Assigned	31,000,233	Post-96 WS 5, line 4
2	General Plant	0				0	
3	Total (line 1+2)					31,000,233	
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)	1,334,532	Directly Assigned	1,334,532	Directly Assigned	1,334,532	Plant Data Support 5
7	General Plant Accum. Depreciation	0		0		0	
8	Total (line 6+7)					1,334,532	
			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)	6,170,136	100%	6,170,136	Directly Assigned (a)	6,170,136	Plant Data Support 5
11	Accumulated Deferred Taxes (190)	0		0		0	
12	Total (line 10+11)					6,170,136	
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					1,134,242	Post-96 WS 1, Line 21
23	Administrative & General Expense					212,628	Post-96 WS 1, Line 22
24	Transmission Support Expense					0	Post-96 WS 7
25	Subtotal (line 22+23+24)					1,346,870	
26						0.125	x 45 / 360
27	Total (line 25 * line 26)					168,359	

Notes/ References:

1. Derived based on an annual depreciation rate of 3.12% as approved by FERC for FPL-NED.
2. Accumuated Depreciation ahd Deffered Taxes for Post-2003 Investment not shown because FPL-NED does not have any Post-2003 Investments (2004-2008) eligible for the incentive ROE.

RTO-NE Regional Transmission Service
FPL-NED'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)	313,324	Directly Assigned	313,324	Directly Assigned	313,324	Data Support 5
2	General Depreciation	0		0		0	
3	Total (line 1+2)					313,324	
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 (FPL-NED costs; see note 2)	317,799	100%	317,799	52.7403% (a)	167,608	Form 1
8	General Property Taxes	0		0		0	
9	Total (line 7+8)	317,799				167,608	
	Transmission Operation and Maintenance						
10	Operation and Maintenance (Directly Assigned to Transmission; Allocated to PTF)	2,150,617	Directly Assigned	2,150,617	52.7403% (a)	1,134,242	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	2,150,617				1,134,242	
	Transmission Administrative and General						
15	Administrative and General (FPL-NED costs; see note 2)	403,161					Form 1
16	less Property Insurance (#924) (FPL-NED costs; see note 2)	13,398					Form 1
17	less Regulatory Commission Expenses (#928) (FPL-NED costs; see note 2)	160,343					Form 1
18	less General Advertising Expense (#930.1)	0					
19	Subtotal [line 15 minus (16 thru 18)]	229,420	100% (b)	229,420	52.7403% (a)	120,997	
25	PLUS Property Insurance (FPL-NED costs; see note 2)	13,398	100% (c)	13,398	52.7403% (a)	7,066	Form 1
26	PLUS Regulatory Comm. Exp.: FERC Assessments (FPL-NED costs; see note 2)	160,343	100% (c)	160,343	52.7403% (a)	84,565	Form 1
27	PLUS Trans. Related General Advertising Expense	0		0		0	
28	Total A&G [line 19 plus (25 thru 27)]	403,161		0	52.7403% (a)	212,628	
32	Payroll Tax Expense - Tranmission Related (FPL-NED costs; see note 2)	15,984	100% (b)	15,984	52.7403% (a)	8,430	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.
2. FPL-NED's costs for Test Year directly assigned to transmission and allocated to pre-97/post-96 PTF.

Reference (a) Post-96 WS5, line 6 (PTF/HTF Allocation Factor applicable to FPL-NED)
(b) Post-96 WS5, line 14 (Wage and Salary Allocation Factor applicable to FPL-NED)
(c) Post-96 WS5, line 19 (Transmission Plant Allocation Factor applicable to FPL-NED.)

RTO-NE Regional Transmission Service
FPL-NED'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.		FPL NED	Reference
	PTF/HTF Transmission Plant Allocation Factor		
1	PTF Transmission Investment (Pre 1997)	19,303,754	Plant Data Support 1 or Form 1
2	Total Transmission Investment	58,779,035	Plant Data Support 1 or Form 1, and Plant Data 4 (See note 1)
3	Percent Allocation	32.8412%	Line 1 / line 2
	PTF/HTF Transmission Plant Allocation Factor		
4	PTF Transmission Investment (Post-1996)	31,000,233	Plant Data Support 1 and Plant Data Support 4 (See Note 2)
5	Total Transmission Investment	58,779,035	Plant Data Support or Form 1
6	Percent Allocation	52.7403%	Line 4 / line 5
	Transmission Wages and Salaries Allocation Factor		
7	Direct Transmission Wages and Salaries	147,777	Form 1
8	Affiliated Company Transmission Wages and Salaries	0	Form 1
9	Total Transmission Wages and Salaries	147,777	Sum Lines 7 + 8
10	Total Wages and Salaries	181,414	Form 1
11	Administrative and General Wages and Salaries	33,637	Form 1
12	Affiliated Company Wages and Salaries less A&G	0	
13	Total Wages and Salaries net of A&G	147,777	Sum Lines 10 + 11 + 12
14	Percent Allocation	100.0000%	Line 9 / Line 13
	Plant Allocation Factor		
15	Total Transmission Investment	58,779,035	Form 1
16	plus Transmission-Related General Plant	0	
17	Total Transmission Related Investment	58,779,035	Sum Lines 15 + 16
18	Total Plant in Service	58,779,035	Form 1
19	Percent Allocation	100.0000%	Line 17 / Line 18
	Pre-1997 and Post 1996 Transmission Plant		
20	PTF PRE 1997 Transmission Investment	19,303,754	Plant Data Support or Form 1
21	PTF POST 1996 Transmission Investment	31,000,233	Plant Data Support or Form 1
22	Total PTF Transmission Plant	50,303,987	Sum Lines 20 + 21
23	Percentage PTF PRE 1997 Transmission Investment	38.3742%	Line 20 / Line 22
24	Percentage PTF POST 1996 Transmission Investment	61.6258%	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	58,779,035	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	58,779,035	
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 FPL-NED's Local Customer as a Direct Assignment Facilities Charge associated with upgraded generator interconnection facilities.

2 Post-96 PTF Investment includes all such PTF investment plus amounts associated with FPL-NED'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 FPL-NED's requested amount for regional cost recovery and is subject to refund or surcharge pending final determination.

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

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

RTO-NE Regional Transmission Service

FPL-NED'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

			FPL NED	
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 FPL's 88.22889% ownership share in the Seabrook Substation.

RTO-NE Regional Transmission Service
FPL-NED'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.	I. FORECASTED TRANSMISSION REVENUE REQUIREMENTS	Period	Attachment F Reference *Section:*	**FPL-NED**	Reference
1	Forecasted Transmission Plant Additions	2010	Appendix C	$2,491,000	Note 1
2	Carrying Charge Factor		Appendix C	16.38%	Line 15
3	Total Forecasted Revenue Requirements (Lines 1*2)			$408,014	Line 1 x Line 2
	II. CARRYING CHARGE FACTOR				
4	Investment Return and Income Taxes (Post-'96 / Pre-'04 Investments)		(A)	$3,241,458	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)	313,324	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)	167,608	Post-96, WS 1, line 19
10	Payroll Tax Expense		(F)	8,430	Post-96, WS 1, line 20
11	Operation & Maintenance Expense		(G)	1,134,242	Post-96, WS 1, line 21
12	Administrative & General Expense		(H)	212,628	Post-96, WS 1, line 22
13	Total Expenses (Lines 4 thru 12)			$5,077,690	Sum lines 4 thru 12
14	PTF Transmission Plant		(A)(1)(a)	$31,000,233	Post-96, WS 1, line 4
15	Carrying Charge Factor (Lines 13/14)			16.38%	Line 13 / Line 15

Note:

1 Forecast Plant Addition includes following projects expected to be placed in service / closed to books by 12/31/10:

- Replace 9 Lightning Arrestors	$ 672,000
- Replace Sequence Event Recorder & Digital Fault Recorder	979,000
- Relay Upgrade Line Sect. 363	840,000
Total Estimated Capital Additions placed in service during 2009	$ 2,491,000

DONE

FPL-NED's PTF Annual Transmission Revenue Requirements
per Tariff Attachment F of the ISO-NE Open Access Transmission Tariff

Short-Term Revenues Received Under ISO-NE Tariff

Line No.	(a) Revenue Source	(b) Total Amount	Reference
1	TOUT Revenues	$1,458	ISO-NE
2	Post-96 PTF Plant Allocator	61.6%	Post-96 WS5, line 24
3	Pre-97 PTF Plant Allocator	38.4%	Post-96 WS5, line 23
4	Post-96 Revenues	$899	Line 1 x Line 2
5	Pre-97 Revenues	$559	Line 1 x Line 3

Sheet: Worksheet 1

FPL-NED
Annual Revenue Requirements of PTF Facilities
Supporting True Up for Rates Effective June 1, 2009

Shading denotes an input

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	PRE97	POST 1996	Reference
1	Transmission Plant		$ 19,303,754	$ 31,000,233	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)		$ 19,303,754	$ 31,000,233	Per-97 and Post-96 WS1
5	Accumulated Depreciation	Appendix C	$ 6,724,974	$ 1,334,532	Per-97 and Post-96 WS1
6	Accumulated Deferred Income Taxes	Appendix C	1,000,912	6,170,136	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)		$ 11,577,868	$ 23,495,565	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	191,355	168,359	Per-97 and Post-96 WS1
13	Total Investment Base (Line 9+10+11+12)		$ 11,769,223	$ 23,663,924	Per-97 and Post-96 WS1

	II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	Appendix C	$ 1,612,135	$ 3,241,458	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	650,426	313,324	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	104,369	167,608	Per-97 and Post-96 WS1
20	Payroll Tax Expense	Appendix C	5,249	8,430	Per-97 and Post-96 WS1
21	Operation & Maintenance Expense	Appendix C	706,288	1,134,242	Per-97 and Post-96 WS1
22	Administrative & General Expense	Appendix C	132,403	212,628	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	692,146	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	(559)	(899)	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 2009 Form 1 Total Revenue Requirements (Line 14 thru 28)		$ 3,902,457	$ 5,076,792	Per-97 and Post-96 WS1
31	As-Billed June 1, 2008 - May 31, 2009 less True-Up component		$ 7,330,562	$ 1,560,591	June 2, 2009 RNS Rates
32	**True-Up (Over) / Under Collection** (line 30-31)		**$ (3,428,105)**	**$ 3,516,201**	line 30 less line 31

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

Undercollection / (Overcollection)			
PRE97	$	(3,428,105)	Overcollection
Post1996	$	3,516,201	Undercollection

Line No.	Initial Billing Period	PRE97 Balance	POST 1996 Balance	FERC Monthly Interest Rate	PRE97 Interest	POST 1996 Interest	
1	June 2009	$ (3,428,104.80)	$ 3,516,201	0.28%	$ (9,598.69)	$ 9,845	
					-		
2	July 2009	(3,437,703.49)	3,526,046.37	0.27%	(9,281.80)	9,520.33	
3	August 2009	(3,437,703.49)	3,526,046.37	0.27%	(9,281.80)	9,520.33	
4	September 2009	(3,437,703.49)	3,526,046.37	0.27%	(9,281.80)	9,520.33	
					-		
6	October 2009	(3,465,548.89)	3,554,607.35	0.27%	(9,356.98)	9,597.44	
7	November 2009	(3,465,548.89)	3,554,607.35	0.27%	(9,356.98)	9,597.44	
8	December 2009	(3,465,548.89)	3,554,607.35	0.27%	(9,356.98)	9,597.44	
					-		
9	January 2010	(3,493,619.84)	3,583,399.67	0.27%	(9,432.77)	9,675.18	
10	February 2010	(3,493,619.84)	3,583,399.67	0.27%	(9,432.77)	9,675.18	
11	March 2010	(3,493,619.84)	3,583,399.67	0.27%	(9,432.77)	9,675.18	
					-		
12	April 2010	(3,521,918.16)	3,612,425.21	0.27%	(9,509.18)	9,753.55	
13	May 2010	(3,521,918.16)	3,612,425.21	0.27%	(9,509.18)	9,753.55	
14			Total Interest		$ (112,832)	$ 115,731	
15			True-Up		$ (3,428,105)	$ 3,516,201	
16			**Total TU & Int**		**$ (3,540,937)**	**$ 3,631,932**	**$ 90,996**

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**
						-		

Amount per

	Pre - 97	Post - 96						Total Post - 96	Total Pre 97 and Post 96	FERC FORM 1 Footnote
		Pre -2004	2004 Additions	2005 Additions	2006 Additions					
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)	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**		

	Pre - 97	Post - 96							Total Pre 97 and Post 96	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	
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**

	Pre - 97	Post - 96								Total Pre 97 and Post 96	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 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											

	Pre - 97	Post - 96								Total Pre 97 and Post 96	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	
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)			

	Pre - 97	Post - 96								Total Pre 97 and Post 96	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	
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**

Gross Plant In-Service at 12/31/2009 per Form 1 76,280,815

All above information from FPL-NED's accounting records

Change in Plant in Service
Year 2009

Accounting Month		**PTF Only** Additions	Retirements	Removal	Total PTF	**Non PTF** NPTF	GSU-C	FUT	**LNS** Sum of PTF, NPTF GSU-C,FUT	GSU	SS	5-Br3eaker Reilability Project	Grand Total
January	Micro WV	341,803	(59,467)	(3,000)	279,336				279,336				279,336
January	Gas Cart	149,308			149,308	5,825	17,218		172,352				172,352
February	Micro WV	(127)			(127)				(127)				(127)
March	Micro WV	1,206			1,206				1,206				1,206
March	SCADA	350,719			350,719				350,719				350,719
March	Battery Charger		(21,827)		(21,827)	(873)	(582)	(582)	(23,864)	(873)	(4,365)		(29,103)
April	Micro WV	1,157			1,157				1,157				1,157
April	SCADA	64,457			64,457				64,457				64,457
April	Battery Charger		2,349		2,349	94	63	62.63	2,568	94	470		3,131
May	SCADA	60,397	-		60,397				60,397				60,397
May	Micro WV	106,888			106,888				106,888				106,888
May	No989-09-TOL	110,276			110,276				110,276				110,276
June	Micro WV	(12,627)			(12,627)				(12,627)				(12,627)
June	SCADA	22,173			22,173				22,173				22,173
June	No989-09-TOL	45,639			45,639				45,639				45,639
July	Micro WV	(122)			(122)				(122)				(122)
July	SCADA	142,158			142,158				142,158				142,158
July	No989-09-TOL	(42,672)			(42,672)				(42,672)				(42,672)
August	SCADA	6,169			6,169				6,169				6,169
September	SCADA	39,364			39,364				39,364				39,364
October	SCADA	(56,073)			(56,073)				(56,073)				(56,073)
October	No989-PR J52	-	(1,941,328)		(1,941,328)	(282,068)	(74,386)	(61,045)	(2,358,827)		(75,140)	[illegible]	
November	No989-PR J52	-			-				-			1,129,741	1,129,741
November	SCADA	1,117			1,117				1,117				1,117
December	SCADA	10,966			10,966				10,966				10,966
December	SCADA	1,012			1,012				1,012				1,012
	Total	**1,343,187**	**(2,020,274)**	**(3,000)**	**(680,087)**	**(277,022)**	**(57,687)**	**(61,564)**	**(1,076,361)**	**(779)**	**(79,036)**	**46,469,812**	**45,313,636**

Micro WV	438,178	(59,467)	(3,000)	375,711	-	-	-	375,711	-	-	-	375,711
Gas Cart	149,308	-	-	149,308	5,825	17,218	-	172,352	-	-	-	172,352
Tools	113,242	-	-	113,242	-	-	-	113,242	-	-	-	113,242
Battery Charger	-	(19,479)	-	(19,479)	(779)	(519)	(519)	(21,297)	(779)	(3,896)	-	(25,972)
SCADA	642,458	-	-	642,458	-	-	-	642,458	-	-	-	642,458
Total Excl 5-Bkr. Reliabiltiy	**1,343,187**	**(78,946)**	**(3,000)**	**1,261,240**	**5,046**	**16,699**	**(519)**	**1,282,466**	**(779)**	**(3,896)**	**-**	**1,277,791**
5-Bkr. Reliabiltiy Project	-	(1,941,328)		(1,941,328)	(282,068)	(74,386)	(61,045)	(2,358,827)	-	(75,140)	[illegible]	
Total Incl 5-Bkr. Project	**1,343,187**	**(2,020,274)**	**(3,000)**	**(680,087)**	**(277,022)**	**(57,687)**	**(61,564)**	**(1,076,361)**	**(779)**	**(79,036)**	**46,469,812**	**45,313,636**

Florida Power & Light Company - New England Division
Statement AE
Summary
Page 1 of 1

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.	Description			(a)	(b)	(c) (a + b)	(d)	(e)	(f) (c+d+e)	(g)		(h)		(i)
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				(a)	(b)	(c)	(d)	(e)	(f)	(g)		(h)		(i)
13		100%	88.22889%			(a + b)			(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	[illegible]	$		$ 1,213,443		$ 33,163,757
20														
21									88.22889%					
22	As of May 31, 2004 estimated/actual	100%	88.22889%			PTF			Total					
23				PTF	NPTF	NPTF	GSU-C	FUT	LNS	GSU	GSU-Diff	SS		Total
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
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
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
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
29														
30	As of December 31, 2004													
31														
32	Plant in Service	$ 53,235,742	$ 46,969,305	$ [illegible]	$ 25,153,388	$	$ 2,712,652	$ 363,481	$ [illegible]	$ 21,427	$	$ [illegible]		$
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
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
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
36														
37									88.22889%					
54														
55	**As of December 31, 2005**	100%	88.22889%			PTF			Total					
56		MEMO ONLY		PTF	NPTF	NPTF	GSU-C	FUT	LNS	GSU	GSU-Diff	SS		Total
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**
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**
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**
66														
67									88.22889%					
84														
85	**As of December 31, 2006**	100%	88.22889%			PTF			Total					
86		MEMO ONLY		PTF	NPTF	NPTF	GSU-C	FUT	LNS	GSU	GSU-Diff	SS		Total
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**
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**
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**
91														
97									88.22889%					
114			88.22889%			PTF			Total					
115	**As of December 31, 2007**	100%		PTF	NPTF	NPTF	GSU-C	FUT	LNS	GSU		SS		Total
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**
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**
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**
121														
129									88.22889%					
146			88.22889%			PTF			Total					
147	**As of December 31, 2008**	100%		PTF	NPTF	NPTF	GSU-C	FUT	LNS	GSU	GSU-Diff	SS		Total
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**
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**
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**
153														
161									88.22889%					
162			88.22889%			PTF			Total					

163	**Depreciation Expense for 2009**		MEMO ONLY		PTF	NPTF	NPTF	GSU-C	FUT	LNS	GSU	GSU-Diff	SS	Project 52	Total
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
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
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
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
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
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
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
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
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
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
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
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
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
178															
179				88.22889%			PTF			Total	Memo Only				
180	**As of December 31, 2009**		100%		PTF	NPTF	NPTF	GSU-C	FUT	LNS	GSU	GSU-Diff	SS	Project 52	Total
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**
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**
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**
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
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)
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)
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

Plant Data Support for FPL-NED'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$
	100%	88.22889%		88.22889%
GSU Breakers (11 & 12)	20,665,210	18,232,685	2009	10,120,753
Structure	13,651,543	12,044,605	2009	12,044,605
Newington Replacement Breakers / Associated Bus	13,394,329	11,817,668	2009	11,817,668
Breaker 25	5,015,540	4,425,155	2009	4,425,155
Bus 1 Connection (50% Newtington / 50% GSU)	3,341,790	2,948,424	2009	2,264,527
Bus 2 Connection (50% Newington / 50% GSU)	4,018,797	3,545,740	2009	2,861,843
Bus 5	3,326,870	2,935,260	2009	2,935,260
	63,414,079	55,949,538		46,469,812

Plant Cost of Direct Assignment Charges excluded from RNS and LNS Transmission Rates		2009$ DAF	Percentage of Plant
	GSU	10,120,753	21.7792%
	40% Structure	4,817,842	10.3677%
	50% Bus 1	1,132,263	2.4366%
	50% Bus 2	1,430,922	3.0793%
	Total	17,501,780	37.6627%

Plant Cost of 5-Breaker Project PTF included in RNS		RNS	
	60% Structure	7,226,763	15.5515%
	Newington Bkrs	11,817,668	25.4308%
	Bkr 25	4,425,155	9.5226%
	50% Bus 1	1,132,263	2.4366%
	50% Bus 2	1,430,922	3.0793%
	Total	26,032,771	56.0208%
Plant Cost of 5-Breaker Project PTF included in LNS		**LNS**	
	Bus 5	2,935,260	6.3165%
Total DAF+RNS+LNS		**46,469,812**	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	100.00%	NA	$	796,182	Form 1
Pre-97 PTF	81.69%	NA		650,426	Plant Data Support 1
Post-96 PTF	18.31%	NA		145,756	Plant Data Support 1

Depreciation Expense	Percentage	Source		Reliabilty Upgrade (See Note)	Source
Total Pending a TCA Review (Reliability Upgrade Project)	100.00%	NA	$	299,116	Form 1
Pool-Supported PTF (pending TCA approval)	56.02%	Plant Data Support 4		167,567	(a) x (c)
Costs not requested to be Pool-Supported	43.98%	Plant Data Support 4		131,549	(a) x (c)

Derivation of Accumulated Depreciation Reserve

Accumulated Depreciation Reserve Not Subject to Pending TCA Review	(a) Percentage	(b) Source		(c) Pool-Supported PTF	Source
Total PTF Related	100.00%	NA	$	7,891,939	Form 1
Pre-97 PTF	85.21%	NA		6,724,974	Plant Data Support 1
Post-96 PTF	14.79%	NA		1,166,965	Plant Data Support 1

Accumulated Depreciation Reserve	Percentage	Source		Reliabilty Upgrade (See Note)	Source
Total Pending a TCA Review (Reliability Upgrade Project)	100.00%	NA	$	299,116	Form 1
Pool-Supported PTF (pending TCA approval)	56.02%	Plant Data Support 4		167,567	(a) x (c)
Costs not requested to be Pool-Supported	43.98%	Plant Data Support 4		131,549	(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	$	2,608,294	Form 1
Pre-97 PTF	38.37%	WS 5		1,000,912	(a) x (c)
Post-96 PTF	61.63%	WS 5		1,607,382	(a) x (c)

Accumulated Depreciation Reserve	Percentage	Source		Reliabilty Upgrade (See Note)	Source
Total Pending a TCA Review (Reliability Upgrade Project)	100.00%	NA	$	8,144,746	Form 1
Pool-Supported PTF (pending TCA approval)	56.02%	Plant Data Support 4		4,562,754	(a) x (c)
Costs not requested to be Pool-Supported	43.98%	Plant Data Support 4		3,581,992	(a) x (c)

Note: The Reliabilty Upgrade pending TCA review and approval is related to a project implemented under the approved Propolsed Plan Application FPLC-08-T01. The amount of Depreciation Expense included in PTF revenue requirements is equal to the percentage of total project costs FPL-NED 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.

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:	21-May-10
Revenue Requirements for (year):	Calendar Year 2009
Rates Effective for the period:	June 2010
through:	May 2011
Customer:	Holyoke Gas & Electric Department
Customer ID:	44
Network Load ID:	73
Customer's NABS Number:	18
Name of Participant responsible for customer's billing:	Brian C. Beauregard
DUNs number of Participant responsible for customer's billing:	08-465-0050

	Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I =	1,072,895	(a)	516,340	(f)
Total of Attachment F - Section J - Support Revenue	0	(b)	0	(g)
Total of Attachment F - Section K - Support Expense	43,255	(c)	0	(h)
Total of Attachment F - Section (L through O)	(687)	(d)	0	(i)
Sub Total - Sum (A through I) - J + K + (L through O)	1,115,463	(e)=(a)-(b)+(c)+(d)	516,340	(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	N/A		34,283	(k)
Annual True-up (per Attachment C to Attachment F Implementation Rule)	28,217	(l)	138,643	(m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)	1,143,680	(n)=(e)+(l)	689,266	(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)			1,832,946	(p)=(n)+(o)

Sheet: TrueUp

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

				Pre 1997	**Post 1996**	
1	2009 Est. Transmission Revenue Requirements (as billed	6/09-05/10	Appendix C	1,088,158	382,181	ATRR - Prior Year
2	2009 Actual Annual RR			1,115,463	516,340	Input Panel Subtotals
3	True-up Over/(Under) (Line 1 - Line 2)			-27,305	-134,159	

	Undercollection / (Overcollection)
PRE97	27,305
Post1996	$134,159

Initial Billing Period		PRE97 Balance	POST 1996 Balance	FERC Monthly Interest Rate		PRE97 Interest		POST 1996 Interest
June 2009	$	27,305	134,159	0.28%	$	76	$	376
July 2009	$	27,381	134,534	0.28%		77		377
August 2009	$	27,381	134,534	0.28%		77		377
September 2009	$	27,381	134,534	0.27%		74		363
October 2009	$	27,608	135,651	0.28%		77		380
November 2009	$	27,608	135,651	0.27%		75		366
December 2009	$	27,608	135,651	0.28%		77		380
January 2010	$	27,837	136,777	0.28%		78		383
February 2010	$	27,837	136,777	0.25%		70		342
March 2010	$	27,837	136,777	0.28%		78		383
April 2010	$	28,063	137,885	0.27%		76		372
May 2010	$	28,063	137,885	0.28%		79		386
			Total Interest		**$**	**913**	**$**	**4,484**
			True-Up			27,304.60		$134,159
			Total TU & Int		$	28,217	$	138,643

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	2010	Appendix C	$139,000	
2		Carrying Charge Factor		Appendix C	24.66%	
3		Total Forecasted Revenue Requirements (Lines 1*2)			$34,283	
	II.	CARRYING CHARGE FACTOR				
4		Investment Return and Income Taxes		(A)	$136,891	Worksheet 1a, line 14
5		Depreciation Expense		(B)	$38,362	Summary, line 15
6		Amortization of Loss on Reacquired Debt		(C)	$39,121	Summary, line 16
7		Investment Tax Credit		(D)	$0	Summary, line 17
8		Property Tax Expense		(E)	$29,995	Summary, line 18
9		Payroll Tax Expense		(F)	$667	Summary, line 19
10		Operation & Maintenance Expense		(G)	$166,592	Summary, line 20
11		Administrative & General Expense		(H)	$104,712	Summary, line 21
12		Total Expenses (Lines 4 thru 11)			$516,340	
13		PTF Transmission Plant		(A)(1)(a)	$2,093,511	Summary, line 1
14		Carrying Charge Factor (Lines 12/13)			24.66%	

Sheet: Summary 0609-0510

Holyoke Gas & Electric Department
Annual Revenue Requirements of pre-1997 & post-1996 PTF
for costs as billed in 2009 06/09-05/10

Line No.		Attachment F Reference	Pre 1997	Post 1996	Reference
	I. INVESTMENT BASE	*Section:*			
1	Transmission Plant	(A)(1)(a)	4,271,276	1,497,273	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	269,032	94,308	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)		4,540,308	1,591,581	
5	Accumulated Depreciation	(A)(1)(d)	2,951,813	1,034,743	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)	41,818	14,659	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)		1,630,313	571,497	
10	Prepayments	(A)(1)(h)	1,628,884	570,997	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	73,746	25,851	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	74,303	23,537	Worksheet 3, line 23 column 5
				0	
13	Total Investment Base (Line 9+10+11+12)		3,407,246	1,191,882	
II.	REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	289,616	101,310	Worksheet 2
15	Depreciation Expense	(B)	85,214	29,871	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	41,818	14,659	Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)	0	0	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	54,907	19,247	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	1,478	518	*Worksheet 4, line 17 column 5*
20	Operation & Maintenance Expense	(G)	326,923	114,601	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	210,234	73,696	Worksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0	0	Worksheet 7
22a	Share of Seabrook Transmission Revenue Requirement		21,449	0	From MMWEC Analysis of Holyoke's % Share
23	Transmission Support Revenue	(J)	0	0	Worksheet 7
24	Transmission Support Expense	(K)	57,268	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)	(321)	0	NEPOOL Sch 1: ST Through and Out Revenues (TOUT Sch 1)
28	Transmission Rents Received from Electric Property	(O)	(428)	0	Page 37 line 18b * TWSAF * PTFPAF
29	Total Revenue Requirements (Line 14 thru 28)		1,088,158	353,902	

Shading denotes an input

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	Holyoke	Reference
1	Transmission Plant	(A)(1)(a)	4,271,276	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	248,971	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)		4,520,247	
5	Accumulated Depreciation	(A)(1)(d)	2,812,981	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)	79,817	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)		1,787,083	
10	Prepayments	(A)(1)(h)	1,353,678	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	75,831	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	74,598	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		3,291,190	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	279,751	Worksheet 2
15	Depreciation Expense	(B)	78,269	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	79,817	Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)	0	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	61,197	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	1,360	*Worksheet 4, line 17 column 5*
20	Operation & Maintenance Expense	(G)	339,889	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	213,638	Worksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Charge	(I)	0	Worksheet 7
22a	Share of Seabrook Transmission Revenue Requirement		18,974	From MMWEC Analysis of Holyoke's % Share
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	43,255	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)	(241)	NEPOOL Sch 1: ST Through and Out Revenues (T(
28	Transmission Rents Received from Electric Property	(O)	(446)	Page 37 line 18b * TWSAF * PTFPAF
29	Total Revenue Requirements (Line 14 thru 28)		1,115,463	

Shading denotes an input

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	Holyoke	Reference
1	Transmission Plant	(A)(1)(a)	2,093,511	Worksheet 3a, line 1 column 5
2	General Plant	(A)(1)(b)	122,030	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)		2,215,541	
5	Accumulated Depreciation	(A)(1)(d)	1,378,745	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)	39,121	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)		875,917	
10	Prepayments	(A)(1)(h)	663,487	Worksheet 3a, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	37,167	Worksheet 3a, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	33,913	Worksheet 3a, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		1,610,484	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	136,891	Worksheet 2a
15	Depreciation Expense	(B)	38,362	Worksheet 4a, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	39,121	Worksheet 4a, line 4 column 5
17	Investment Tax Credit	(D)	0	Worksheet 4a, line 5 column 5
18	Property Tax Expense	(E)	29,995	Worksheet 4a, line 8 column 5
19	Payroll Tax Expense	(F)	667	*Worksheet 4a, line 17 column 5*
20	Operation & Maintenance Expense	(G)	166,592	Worksheet 4a, line 13 column 5
21	Administrative & General Expense	(H)	104,712	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)		516,340	

Holyoke Gas & Electric Department
Annual Revenue Requirements
for costs in 2009
Pre-1997

Shading denotes an input

		CAPITALIZATION 12/31/09	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) / 3,291,190) 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) / 3,291,190) + 0.0000000)* 0
(1 - 0)

= 0.0000000

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

		(PTF)	
INVESTMENT BASE	$	3,291,190	From Worksheet 1
x Cost of Capital Rate		0.0850000	
= Investment Return and Income Taxes		279,751	To Worksheet 1

Holyoke Gas & Electric Department
Annual Revenue Requirements
for costs in 2009
Post-1996

Shading denotes an input

		CAPITALIZATION 12/31/09	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 inc

(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) / 3,291,190) 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) / 3,291,190) + 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	$	1,610,484	From Worksheet 1	1,610,484	From Worksheet 1	1,610,484	From Worksheet 1
% Allocated to respective period		0.34%		99.66%		0.00%	
PERIOD INVESTMENT BASE		5,420		1,605,064		0	
x Cost of Capital Rate		0.0850000		0.0850000	Not included in RSP	0.0950000	Included in RSP
= Investment Return and Income Taxes		461	To Worksheet 1	136,430	To Worksheet 1	0	To Worksheet 1

Sheet: Worksheet 3

Holyoke Gas & Electric Department

Pre-1997

Shading denotes an input

Line No.		(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
	Transmission Plant						
1	Transmission Plant	8,285,056		8,285,056		4,271,276	Line 1, Worksheet 5
2	General Plant	7,113,128	6.7893% (a)	482,932	51.5540%	248,971	Page 8B, line 30g less line
3	Total (line 1+2)			8,767,988		4,520,247	
4	Transmission Plant Held for Future Use	0		0	51.5540%	0	None known
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	5,122,914		5,122,914	51.5540%	2,641,067	Page 8A, line 31g less Page 16, line 31g
6	General Plant Accum.Depreciation	4,911,599	6.7893% (a)	333,463	51.5540%	171,914	(Page 8B, line 30g less lin (Page 17, line 30g less lin
7	Total (line 5+6)			5,456,377		2,812,981	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	0	7.1201% (c)	0	51.5540%	0	None known
9	Accumulated Deferred Taxes (190)	0	7.1201% (c)	0	51.5540%	0	None known
10	Total (line 8+9)			0		0	
11	Transmission loss on Reacquired Deb	2,174,430	7.1201% (c)	154,822	51.5540%	79,817	Page 13, line 28d
	Other Regulatory Assets						
12	FAS 106	0	6.7893% (a)	0	51.5540%	0	None known
13	FAS 109	0	7.1201% (c)	0	51.5540%	0	None known
14	Other Regulatory Liabilities (254.DK)	0	7.1201% (c)	0	51.5540%	0	
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments	38,674,799	6.7893% (a)	2,625,748	51.5540%	1,353,678	Page 10, line 26c
17	Transmission Materials and Supplies	2,065,844	7.1201% (a)	147,090	51.5540%	75,831	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)	
18	Cash Working Capital		
19	Operation & Maintenance Expense	339,889	Worksheet 1, Line 20
20	Administrative & General Expense	213,638	Worksheet 1, Line 21
21	Transmission Support Expense	43,255	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)	596,782	
23		0.125	x 45 / 360
24	Total (line 22 * line 23)	74,598	

(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

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	8,285,056		8,285,056		2,093,511	Line 1, Worksheet 5
2	General Plant	7,113,128	6.7893% (a)	482,932	25.2685%	122,030	Page 8B, line 30g less line
3	Total (line 1+2)			8,767,988		2,215,541	
4	Transmission Plant Held for Future Use	0		0	25.2685%	0	None known
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	5,122,914		5,122,914	25.2685%	1,294,484	Page 8A, line 31g less Page 16, line 31g
6	General Plant Accum.Depreciation	4,911,599	6.7893% (a)	333,463	25.2685%	84,261	(Page 8B, line 30g less lin (Page 17, line 30g less lin
7	Total (line 5+6)			5,456,377		1,378,745	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	0	7.1201% (c)	0	25.2685%	0	None known
9	Accumulated Deferred Taxes (190)	0	7.1201% (c)	0	25.2685%	0	None known
10	Total (line 8+9)			0		0	
11	Transmission loss on Reacquired Deb	2,174,430	7.1201% (c)	154,822	25.2685%	39,121	Page 12, line 28b
	Other Regulatory Assets						
12	FAS 106	0	6.7893% (a)	0	25.2685%	0	None known
13	FAS 109	0	7.1201% (c)	0	25.2685%	0	None known
14	Other Regulatory Liabilities (254.DK)	0	7.1201% (c)	0	25.2685%	0	
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments	38,674,799	6.7893% (a)	2,625,748	25.2685%	663,487	Page 10, line 26c
17	Transmission Materials and Supplies	2,065,844	7.1201% (a)	147,090	25.2685%	37,167	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	166,592	Worksheet 41a, Line 20
20	Administrative & General Expense	104,712	Worksheet 41a, Line 21
21	Transmission Support Expense	0	Worksheet 41a, Line 24
22	Subtotal (line 19+20+21)	271,304	
23		0.125	x 45 / 360
24	Total (line 22 * line 23)	33,913	

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

Holyoke Gas & Electric Department

Pre-1997

Shading denotes an input

Line No.		(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Mass DTE AR Reference for col (1)
	Depreciation Expense						
1	Transmission Depreciation	128,706		128,706	51.5540%	66,353	Page 16, line 31d
2	General Depreciation	340,436	6.7893% (a)	23,113	51.5540%	11,916	Page 17, line 30d less line 29 Telecom
3	Total (line 1+2)			151,819		78,269	
4	Amortization of Loss on Reacquired Debt	2,174,430	7.1201% (c)	154,822	51.5540%	79,817	Page 13, line 28d
5	Amortization of Investment Tax Credits	0	7.1201% (c)	0	51.5540%	0	None known
	Property Taxes *						
6	Transmission Property Taxes	113,347		113,347	51.5540%	58,435	See below
7	General Property Taxes	78,914	6.7893% (a)	5,358	51.5540%	2,762	
8	Total (line 6+7)			118,705		61,197	
	Transmission Operation and Maintenance	PER INTERPRETATIVE GUIDANCE DOCUMENT SECTION II.G RULES FOR HGED					
9	Operation and Maintenance	3,256,613		3,256,613	51.5540%	1,678,914	Page 40, line 50b
10	Transmission of Electricity by Others - #565	2,597,326		2,597,326	51.5540%	1,339,025	Page 40, line 38b
11	Load Dispatching - #561	0		0	51.5540%	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	659,287		659,287	51.5540%	339,889	
	Transmission Administrative and General						
14	Administrative and General	6,143,230					Page 42, line 7b less line 5b, less pg 41 line 56b te
15	*less Property Insurance (#924)*	*452,371*					*Page 41, line 49b*
16	*less Regulatory Commission Expenses (#928)*	*0*					*Page 41, line 52b*
17	*less General Advertising Expense (#930.1)*	*61,606*					*G/L Acct 930-03 Public Goodwill*
18	Subtotal [line 14 minus (15 thru 17)]	5,629,253	6.7893% (a)	382,187	51.5540%	197,033	
19	*PLUS Property Insurance alloc. using Plant Allocation*	*452,371*	*7.1201% (c)*	32,209	51.5540%	16,605	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	*0*	*7.1201% (c)*	0	51.5540%	0	
21	*PLUS Trans. Related General Advertising Expense*	*0*	*7.1201% (c)*	0	51.5540%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*6,081,624*		*414,396*		*213,638*	
23	*Payroll Tax Expense*	*38,853*	*6.7893% (a)*	*2,638*	*51.5540%*	*1,360*	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	G/L Acct 926-05
FICA/Medicare	38,853	G/L Acct 926-06
MA Unemployment	0	
MA Universal Health	0	
Total	38,853	*To Line 23*

* Property Taxes	NBV Transmission Plant	3,162,142	Page 16, line 31g
	NBV General Plant	2,201,529	Page 17, line 30g less line 29g telecom
	Local property tax rate - 1st half	35.15	Page 3, line 9 of 2009 DPU State Return
	Local property tax rate - 2nd half	36.54	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 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	128,706		128,706	25.2685%	32,522	Page 16, line 31d
2	General Depreciation	340,436	6.7893% (a)	23,113	25.2685%	5,840	Page 17, line 30d less line 29 Telecom
3	Total (line 1+2)			151,819		38,362	
4	Amortization of Loss on Reacquired Debt	2,174,430	7.1201% (c)	154,822	25.2685%	39,121	Page 13, line 28d
5	Amortization of Investment Tax Credits	0	7.1201% (c)	0	25.2685%	0	None known
	Property Taxes *						
6	Transmission Property Taxes	113,347		113,347	25.2685%	28,641	See below
7	General Property Taxes	78,914	6.7893% (a)	5,358	25.2685%	1,354	
8	Total (line 6+7)			118,705		29,995	
	Transmission Operation and Maintenance	PER INTERPRETATIVE GUIDANCE DOCUMENT SECTION II.G RULES FOR HGED					
9	Operation and Maintenance	3,256,613		3,256,613	25.2685%	822,897	Page 40, line 50b
10	Transmission of Electricity by Others - #565	2,597,326		2,597,326	25.2685%	656,305	Page 40, line 38b
11	Load Dispatching - #561	0		0	25.2685%	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	659,287		659,287	25.2685%	166,592	
	Transmission Administrative and General						
14	Administrative and General	6,143,230					Page 42, line 7b less line 5b, less pg 41 line 56b te
15	*less Property Insurance (#924)*	*452,371*					*Page 41, line 47b*
16	*less Regulatory Commission Expenses (#928)*	*0*					*Page 41, line 50b*
17	*less General Advertising Expense (#930.1)*	*61,606*					*G/L Acct 930-03 Public Goodwill*
18	Subtotal [line 14 minus (15 thru 17)]	5,629,253	6.7893% (a)	382,187	25.2685%	96,573	
19	*PLUS Property Insurance alloc. using Plant Allocation*	*452,371*	*7.1201% (c)*	32,209	25.2685%	8,139	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	*0*	*7.1201% (c)*	0	25.2685%	0	
21	*PLUS Trans. Related General Advertising Expense*	*0*	*7.1201% (c)*	0	25.2685%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*6,081,624*		*414,396*		*104,712*	
23	*Payroll Tax Expense*	*38,853*	*6.7893% (a)*	*2,638*	25.2685%	*667*	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	926-05
FICA/Medicare	38,853	926-06
MA Unemployment	0	
MA Universal Health	0	
Total	38,853	*To Line 23*

* Property Taxes

NBV Transmission Plant	3,162,142	Page 16, line 31g
NBV General Plant	2,201,529	Page 17, line 30g
Local property tax rate - 1st half	35.15	Page 3, line 9 of 2009 DPU State Return
Local property tax rate - 2nd half	36.54	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.		Holyoke		Mass DTE AR Reference
	PTF Transmission Plant Allocation Factor			
		Pre-1997	Post-1996	
1	PTF Transmission Investment	4,271,276	2,093,511	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
2	Total Transmission Investment	8,285,056	8,285,056	Page 8A, line 31g
3	Percent Allocation (Line 1/Line 2)	51.5540%	25.2685%	
	Transmission Wages and Salaries Allocation Factor			
4	Direct Transmission Wages and Salaries	485,571		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)	485,571		
7	Total Wages and Salaries	7,877,635		Page 42, line 25 less telecom Wages
8	Administrative and General Wages and Salaries	725,662		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)	7,151,973		
11	Percent Allocation (Line 6/Line 10)	6.7893%		
	Plant Allocation Factor			
12	Total Transmission Investment	8,285,056		Line 2
13	*plus Transmission-Related General Plant* *(Line 2 of Wkst. 3)*	482,932		*Worksheet 3, Line 2*
14	*= Revised Numerator* *(Line 12 + Line 13)*	8,767,988		
15	Total Plant in Service	123,144,159		Page 8B, line 31g less line 15g, less line 29g telecom
16	Percent Allocation (Line 14 / Line 15)	7.1201%		

(Line #4) Breakdown of Transmission Expenses by FERC #	**Expenses (*)**		**Labor (*)**	**Total from MDTE AR**
560	7,414		304,427	311,841
562	53,671		91,998	145,669
563	-		-	-
566	2,915		17,833	20,748
570	42,035		20,390	62,425
571-00	19,480		48,946	68,427
571-01	48,203		1,976	50,179
		Total	485,571	

(*) From General Ledger Trial Balance Report for December 31, 2009 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

Sheet: Worksheet 7

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

			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]		1,157
	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			2,466
	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**			8,243
	Comerford 115 kV Substation			
	345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line			
	115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line			
	Moore 115 kV Substation	332.1(g)		
	HQ Phase II - AC in MA	332.1(g); [332(g) for CL&P]		17,788
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 394 line	332(g)		1,311
	115 kV Read - Washington V148 line			
NU	**345 kV 363, 369 and 394 Seabrook lines**			1,118
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		0
	345 kV Millstone-Manchester 310 line	330.1(n)		11,171
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
		Total =	0	43,255

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

Holyoke Gas & Electric Department - 2010 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-10	NERC Required Security Improvements per critical infrastructure protection (CIP) standards. Includes both security card key system and video surveillance system.	n/a	n/a	Not Required	Not Required	45000	100%	**$45,000**
Holyoke Gas & Electric Department		Dec-10	Replace 1292 Line Primary Relaying	Planned	Planned	Not Required	Not Required	5000	100%	**$5,000**
Holyoke Gas & Electric Department		May-10	Replace 115 kV Air Disconnect Switches at Holyoke 17L and Ingleside 52W (balance of 2008 planned project, remaining is labor with incidental materials over 3 yr installation period)	Planned	Planned	Not Required	Not Required	12000	75%	**$9,000**
Holyoke Gas & Electric Department		Dec-10	Installation of microprocessor based multifunction unit with breaker failure timing and fault detector for the 1T breakers at both Ingleside and Holyoke Subs to replace existing electromechanical relays	n/a	n/a	Not Required	Not Required	35000	100%	**$35,000**
Holyoke Gas & Electric Department		Dec-10	Replace 1657 Line Primary & Backup Relays at Ingleside 52W	n/a	n/a	Not Required	Not Required	45000	100%	**$45,000**

2010 Forecasted Transmission Plant Additions = $139,000

Account	Description	Debit	Credit
0030-30-560-560-00-1	TRANS OPER SUPV & ENG EXPENSES	7,414.28	.00
0030-30-560-560-00-2	TRANS OPER SUPV & ENG LABOR	304,427.16	.00
0030-30-562-562-00-1	TRANSMISSION STATION EXPENSES	53,670.56	.00
0030-30-562-562-00-2	TRANSMISSION STATION LABOR	91,998.49	.00
0030-30-565-565-01-1	TRANS - P/P WYMAN #4 EXPENSE	5,188.00	.00
0030-30-565-565-02-1	TRANS - PASNY FIRM	251,700.13	.00
0030-30-565-565-03-1	TRANS - PASNY PEAK	6,979.76	.00
0030-30-565-565-15-1	TRANS - P/P STONEY BROOK	896.38	.00
0030-30-565-565-18-1	TRANS - P/P MILLSTONE #3	10,637.61	.00
0030-30-565-565-19-1	TRANS - P/P SEABROOK #1	11,922.13	.00
0030-30-565-565-23-1	TRANS - HYDRO QUEBEC I	11,452.05	.00
0030-30-565-565-24-1	TRANS - HYDRO QUEBEC II	142,953.08	.00
0030-30-565-565-26-1	NEPOOL OATT	2,103,705.63	.00
0030-30-565-565-28-1	NU TRANSMISSION LNS	51,891.00	.00
0030-30-566-566-00-1	MISC TRANSMISSION EXPENSE	2,915.00	.00
0030-30-566-566-00-2	MISC TRANSMISSION PAYROLL	17,832.65	.00
0030-30-570-570-00-1	MAINT TRANSMISSION PLANT EXPENSE	42,034.54	.00
0030-30-570-570-00-2	MAINT TRANSMISSION PLANT LABOR	20,390.37	.00
0030-30-571-571-00-1	MAINT OVERHEAD LINES EXPENSE	19,479.64	.00
0030-30-571-571-00-2	MAINT OVERHEAD LINES LABOR	48,946.03	.00
0030-30-571-571-01-1	TRANS/MAINT CLEARANCE EXPENSE	48,202.62	.00
0030-30-571-571-01-2	TRANS/MAINT CLEARANCE LABOR	1,976.20	.00
ELECTRIC		3,256,613.31	.00
All Fund Totals		3,256,613.31	.00

PREPARED 5/17/10 , 10:51:11 Trial Balance Page 2
PROGRAM MADG125
Holyoke Gas & Electric Department

Account	Description	Debit	Credit
0030-30-930-930-03-1	PUBLIC GOODWILL	52,761.90	.00
0030-30-930-930-03-2	PUBLIC GOODWILL LABOR	8,844.08	.00
ELECTRIC		61,605.98	.00
All Fund Totals		61,605.98	.00

PREPARED 4/28/10 , 16:42:55 Trial Balance Page 2
PROGRAM MADG125
Holyoke Gas & Electric Department

Account	Description	Debit	Credit
0030-30-926-926-06-1	FICA MEDICARE TAX	38,852.92	.00
ELECTRIC		38,852.92	.00
All Fund Totals		38,852.92	.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:	**03-Jun-10**
Revised on:	**N/A**
Revenue Requirements for (year):	**2009**
Customer:	**Hudson**
Customer's NABs Number:	
Name of Participant responsible for customer's billing:	**Hudson**
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	=	3,684	(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)		3,684	(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:	3,684	(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)	3,684	(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)	44,113	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)		44,113	
5	Accumulated Depreciation	(A)(1)(d)	28,599	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)		15,514	
10	Prepayments	(A)(1)(h)	62	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	845	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	226	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		16,647	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	1,332	Worksheet 2
15	Depreciation Expense	(B)	105	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)	421	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	19	*Worksheet 4, line 17 column 5*
20	Operation & Maintenance Expense	(G)	1,751	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	56	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)		3,684	

Hudson Light and Power Department
Annual Revenue Requirements
for costs in 2009

Shading denotes an input

		CAPITALIZATION 12/31/09	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) / 16,647) 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) / 16,647) + 0.0000000)* 0 / (1 - 0)

= 0.0000000

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

		(PTF)	
INVESTMENT BASE	$	16,647	From Worksheet 1
x Cost of Capital Rate		0.0800000	
= Investment Return and Income Taxes		1,332	To Worksheet 1

Shading denotes an input

Line No.		(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
	Transmission Plant						
1	Transmission Plant	51,545	Directly Assigned	51,545		44,113	
2	General Plant	0	0.5385% (a)	0	85.5815%	0	
3	Total (line 1+2)			51,545		44,113	
4	Transmission Plant Held for Future Use	0		0	85.5815%	0	
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	33,417		33,417	85.5815%	28,599	
6	General Plant Accum.Depreciation	0	0.5385% (a)	0	85.5815%	0	
7	Total (line 5+6)			33,417		28,599	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	0	2.6599% (c)	0	85.5815%	0	
9	Accumulated Deferred Taxes (190)	0	2.6599% (c)	0	85.5815%	0	
10	Total (line 8+9)			0		0	
11	Transmission loss on Reacquired Debt	0	2.6599% (c)	0	85.5815%	0	
	Other Regulatory Assets						
12	FAS 106	0	0.5385% (a)	0	85.5815%	0	
13	FAS 109	0	2.6599% (c)	0	85.5815%	0	
14	Other Regulatory Liabilities (254.DK)	0	2.6599% (c)	0	85.5815%	0	
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments	2,731	2.6599% (a)	73	85.5815%	62	
17	Transmission Materials and Supplies	37,114	2.6599% (a)	987	85.5815%	845	

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

Line No.			
18	Cash Working Capital		
19	Operation & Maintenance Expense	1,751	Worksheet 1, Line 20
20	Administrative & General Expense	56	Worksheet 1, Line 21
21	Transmission Support Expense	0	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)	1,807	
23		0.125	x 45 / 360
24	Total (line 22 * line 23)	226	

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

Shading denotes an input

Line No.		(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	Mass DTE AR Reference for col (1)
	Depreciation Expense						
1	Transmission Depreciation	123		123	85.5815%	105	
2	General Depreciation	0	0.5385% (a)	0	85.5815%	0	
3	Total (line 1+2)			123		105	
4	Amortization of Loss on Reacquired Debt	0	2.6599% (c)	0	85.5815%	0	
5	Amortization of Investment Tax Credits	0	2.6599% (c)	0	85.5815%	0	
	Property Taxes *						
6	Transmission Property Taxes	0		0	85.5815%	0	
7	General Property Taxes	18,488	2.6599% (c)	492	85.5815%	421	
8	Total (line 6+7)			492		421	
	Transmission Operation and Maintenance	PER INTERPRETATIVE GUIDANCE DOCUMENT SECTION II.G RULES FOR HGED					
9	Operation and Maintenance	2,046	B-2	2,046	0.855815	1,751	
10	Transmission of Electricity by Others - #565	0		0	0.855815	0	
11	Load Dispatching - #561	0		0	0.855815	0	
12	**Station Expenses & Rents - #562 / #567					0	
13	O&M less lines 10, 11 & 12	2,046		2,046	85.5815%	1,751	
	Transmission Administrative and General						
14	Administrative and General	12,264					
15	*less Property Insurance (#924)*	*0*					
16	*less Regulatory Commission Expenses (#928)*	*0*					
17	*less General Advertising Expense (#930.1)*	*0*					
18	Subtotal [line 14 minus (15 thru 17)]	12,264	0.5385% *(a)*	66	85.5815%	56	
19	*PLUS Property Insurance alloc. using Plant Allocatior*	*0*	*2.6599% (c)*	0	85.5815%	0	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	*0*	*2.6599% (c)*	0	85.5815%	0	
21	*PLUS Trans. Related General Advertising Expense*	*0*	*2.6599% (c)*	0	85.5815%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*12,264*		*66*		*56*	
23	*Payroll Tax Expense*	*4,006*	*0.5385% (a)*	*22*	*85.5815%*	*19*	

(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	4,006	926-05
FICA/Medicare	0	926-06
MA Unemployment	0	
MA Universal Health	0	
Total	4,006	*To Line 23*

* Property Taxes

		Transmission	General		
a	Gross Plant	51,545	-	Worksheet 3, lines 1 & 2	
b	Depr Reserve	33,417	0	Worksheet 3, lines 5 & 6	
c = a - b	Net Book Value	18,128	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	44,113	
2	Total Transmission Investment	51,545	
3	Percent Allocation (Line 1/Line 2)	85.5815%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	255	B-1
5	Affiliated Company Transmission Wages and Salaries	0	
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	255	
7	Total Wages and Salaries	47,374	C-1
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)	47,374	
11	Percent Allocation (Line 6/Line 10)	0.5385%	
	Plant Allocation Factor		
12	Total Transmission Investment	79,842	
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	0	
14	*= Revised Numerator (Line 12 + Line 13)*	79,842	
15	Total Plant in Service	3,001,657	
16	Percent Allocation (Line 14 / Line 15)	2.6599%	

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

Sheet: Worksheet 7

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

Participant	PTF Supporting Facilities	FERC Form 1	TOTAL Revenues (a)	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]		
	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 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	0

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

Hudson Support of the New England PTF for 2009

	HQ II AC BECo	HQ II AC NEP	HQ II Chester SVC NEH	Seabrook Tewksbury NEP	Seabrook Scobie & Newington NU	Millstone 3 NU	Wyman 4 CMP	Total	Seabrook Revenue Requirements	Support and Revenue Requirements Total
Hudson-MMWEC	$ 644.99	$ 9,915.10	$ 4,595.03	$ 6,760.00	$ 5,767.80	$ 3,694.16	$ 1,216.64	$ 32,593.71	$ 97,872.34	$ 130,466.04
Hudson-MJO (Non-MMWEC)	0	0	0	324.05	279.04	0	0	$ 603.09	$ 3,684.00	$ 4,287.09
Total	$ 644.99	$ 9,915.10	$ 4,595.03	$ 7,084.05	$ 6,046.84	$ 3,694.16	$ 1,216.64	$ 33,196.80	$ 101,556.34	$ 134,753.13

(pink)	Data submitted on MMWEC's NEPOOL Annual Transmission Revenue Requirement (ATRR) sheet on 5-21-10
(yellow)	Hudson Non-MMWEC Seabrook Revenue Requirement amount which needs to be added to the MMWEC ATRR sheet submitted on 5-21-10

MAINE ELECTRIC POWER COMPANY
RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/09

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

Shading denotes an input

Submitted on:	May 17, 2010
Revenue Requirements for (year):	Calendar Year 2009
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	=	1,715,886	(a)	357,337	(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)		(2,751,766)	(d)	(573,060)	(i)
Sub Total - Sum (A through I) - J + K + (L through P)		(1,035,879)	(e)=(a)-(b)+(c)+(d)	(215,724)	(j)

Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:	(1,251,603)	(k) = (e) + (j)

MAINE ELECTRIC POWER COMPANY
RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/09

Shading denotes an input

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	TOTAL	POST 96	PRE-97	Reference
			MEPCO			
1	Transmission Plant	(A)(1)(a)	25,445,678	4,385,766	21,059,912	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	1,228,846	211,801	1,017,045	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)		26,674,524	4,597,567	22,076,957	
5	Accumulated Depreciation	(A)(1)(d)	24,225,225	4,175,411	20,049,814	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	461,976	79,625	382,351	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)	608,957	104,959	503,998	Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5+6+7+8)		2,302,318	606,740	2,913,492	
10	Prepayments	(A)(1)(h)	176,927	30,495	146,432	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)	128,092	22,078	106,014	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		2,607,337	659,312	3,165,939	

	II. REVENUE REQUIREMENTS					
14	Investment Return and Income Taxes	(A)	512,698	88,368	424,330	Worksheet 2
15	Depreciation Expense	(B)	228,034	39,303	188,731	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)	307,755	53,044	254,711	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	-	-	-	*Worksheet 4, line 17 column 5*
20	Operation & Maintenance Expense	(G)	808,424	139,338	669,086	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	216,312	37,283	179,029	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)	(1,864,246)	(321,318)	(1,542,928)	
28	Transmission Rents Received from Electric Property	(O)	(277,470)	(47,824)	(229,646)	FF I p.300.19.b
28	MGTSA Revenue	(P)	(1,183,110)	(203,918)	(979,192)	
29	Total Revenue Requirements (Line 14 thru 28)		(1,251,603)	(215,724)	(1,035,879)	

MAINE ELECTRIC POWER COMPANY
RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/09

Shading denotes an input

		CAPITALIZATION 12/31/2009	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		17,961,035	100.00%	11.64%	11.64%	11.64%
TOTAL INVESTMENT RETURN	$	17,961,035	100.00%		11.64%	11.64%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.1164

(b) Federal Income Tax

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

$$= \frac{(0.1164 + (- + -) / 2,607,337) \times 35\%)}{(1 - 0.35)}$$

$$= 0.0626769$$

(c) State Income Tax

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

$$= \frac{(0.1164 + (- + -) / 2,607,337) + 0.0626769)^* 8.93\%}{(1 - 0.0893)}$$

$$= 0.0175596$$

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

		(PTF)	
INVESTMENT BASE	$	2,607,337	From Worksheet 1
x Cost of Capital Rate		0.1966365	
= Investment Return and Income Taxes		512,698	To Worksheet 1

MAINE ELECTRIC POWER COMPANY
RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/09

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	25,445,678		25,445,678		25,445,678	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)			26,674,524		26,674,524	
4	Transmission Plant Held for Future Use	-		-	100.0000%	-	
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	23,005,146		23,005,146	100.0000%	23,005,146	219.25.b
6	General Plant Accum.Depreciation	1,220,079	100.0000% (a)	1,220,079	100.0000%	1,220,079	219.28.b
7	Total (line 5+6)			24,225,225		24,225,225	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	(147,720)	99.8754% (c)	(147,536)	100.0000%	(147,536)	275.9.k
9	Accumulated Deferred Taxes (190)	610,272	99.8754% (c)	609,512	100.0000%	609,512	
10	Total (line 8+9)			461,976		461,976	
11	Transmission loss on Reacquired Debt	-	99.8754% (c)	-	100.0000%	-	
	Other Regulatory Assets/(Liabilities)						
12	FAS 106	-	100.0000% (a)	-	100.0000%	-	
13	FAS 109	(609,717)	99.8754% (c)	(608,957)	100.0000%	(608,957)	278.1.f
14	Other Regulatory Liabilities (254.DK)	-	99.8754% (c)	-	100.0000%	-	
15	Total (line 12+13+14)	(609,717)		(608,957)		(608,957)	
16	Transmission Prepayments	176,927	100.0000% (a)	176,927	100.0000%	176,927	111.57.c
17	Transmission Materials and Supplies	-	99.8754%	-	100.0000%	-	
18	Cash Working Capital						
19	Operation & Maintenance Expense					808,424	Worksheet 1, Line 20
20	Administrative & General Expense					216,312	Worksheet 1, Line 21
21	Transmission Support Expense					-	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					1,024,736	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					128,092	

(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 12/31/09

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	216,538		216,538	100.0000%	216,538	336.7.f
2	General Depreciation	11,496	100.0000% (a)	11,496	100.0000%	11,496	336.9.f
3	Total (line 1+2)			228,034		228,034	
4	Amortization of Loss on Reacquired Debt	-	99.8754% (c)	-	100.0000%	-	
5	Amortization of Investment Tax Credits	-	99.8754% (c)	-	100.0000%	-	
	Property Taxes *						
6	Transmission Property Taxes	308,139	0.998754	307,755	100.0000%	307,755	263.5i-9i
7	General Property Taxes	-	100.0000% (a)	-	100.0000%	-	
8	Total (line 6+7)			307,755		307,755	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	972,851		972,851	100.0000%	972,851	321.112.b
10	Transmission of Electricity by Others - #565	-		-	100.0000%	-	
11	Load Dispatching - #561	164,427		164,427	100.0000%	164,427	321.86b-87b
12	**Station Expenses & Rents - #562 / #567			-	100.0000%	-	
13	O&M less lines 10, 11 & 12	808,424		808,424	100.0000%	808,424	
	Transmission Administrative and General						
14	Administrative and General	216,495					323.194.b
15	*less Property Insurance (#924)*	*12,509*					323.185.b
16	*less Regulatory Commission Expenses (#928)*	*133,993*					323.189.b
17	*less General Advertising Expense (#930.1)*	-					
18	Subtotal [line 14 minus (15 thru 17)]	69,993	100.0000% (a)	69,993	100.0000%	69,993	
19	*PLUS Property Insurance alloc. using Plant Allocation*	*12,509*	*99.8754% (c)*	12,493	100.0000%	12,493	323.185.b
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	*133,993*	*99.8754% (c)*	133,826	100.0000%	133,826	323.189.b
21	*PLUS Trans. Related General Advertising Expense*	-	*99.8754% (c)*	-	100.0000%	-	
22	Total A&G [line 18 plus (19 thru 21)]	*216,495*		*216,312*		*216,312*	
23	*Payroll Tax Expense*	-	*100.0000% (a)*	-	*100.0000%*	-	

MAINE ELECTRIC POWER COMPANY
RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/09

Shading denotes an input

Line No.			Reference
	PTF Transmission Plant Allocation Factor	**MEPCO**	
1	PTF Transmission Investment	25,445,678	207.58.g
2	Total Transmission Investment	25,445,678	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	25,445,678	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)*	26,674,524	
15	Total Plant in Service	26,707,794	207.104.g
16	Percent Allocation (Line 14 / Line 15)	99.8754%	

MAINE ELECTRIC POWER COMPANY
RNS REVENUE REQUIREMENTS
FOR THE UNADJUSTED TEST YEAR ENDED 12/31/09

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 12/31/09

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)		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 12/31/09

MEPCO PTF by Vintage 12/31/09

Sum of amount				
Fer Account	Vintage	Total	PRE	POST
350	1900/01	(83)		
	1970/01	354,307		
	1971/01	408,103		
	1973/01	218		
	1974/01	1,243		
	1976/01	1,336		
	1977/01	617		
	1978/01	19		
	1982/01	1,200		
	1988/01	(2,000)		
	1990/01	26,763	791,723	
	1998/01	1,601		
	2000/01	1,951		
	2003/01	2,513		6,065
350 Total		797,788		
352	1970/01	179,586		
	1984/01	94,112		
	1985/01	45,504		
	1986/01	100,118		
	2000/01	278,364	419,320	278,364
352 Total		697,684		
353	1970/01	1,903,189		
	1971/01	492,619		
	1972/01	5,441		
	1973/01	4,072		
	1975/01	92,738		
	1976/01	553		
	1984/01	814,307		
	1985/01	446,235		
	1986/01	878,674		
	1990/01	277,778		
	1991/01	90,622		
	1992/01	387,662		
	1993/01	257,336		
	1996/01	19,107	5,670,333	
	1997/01	290,311		
	1998/01	109,413		
	2000/01	1,338,400		
	2001/01	148,947		
	2002/01	87,395		
	2003/01	618,942		
	2007/10	198,651		
	2007/12	64,188		
	2008/01	32,095		
	2009/05	12,322		
	2009/07	21,142		2,921,804
353 Total		8,592,137		
354	1971/01	615,353	615,353	
	2008/09	25,473		25,473
354 Total		640,826		
355	1970/01	4,821,816		
	1971/01	4,122,465		
	1973/01	24,679		
	1985/01	38,104		
	2000/01	778,329		
	2009/01	254,898		
	2009/03	64,951	9,007,065	1,098,178
355 Total		10,105,243		
356	1970/01	2,441,731		
	1971/01	2,110,303		
	1985/01	1,490	4,553,524	
	1997/01	7,648		
	2003/01	9,039		
	2009/07	34,411		51,098
356 Total		4,604,622		
359	1992/01	2,594	2,594	
	1997/01	733		
	2001/01	564		
	2009/07	3,486		4,783
359 Total		7,377		
Grand Total		25,445,677	21,059,911	4,385,766

	Municipal Support of the New England PTF for 2009									
									MMWEC's	
	HQ II	HQ II	HQ II	Seabrook	Seabrook				Seabrook	Support and
	AC	AC	Chester	Tewksbury	Scobie &	Millstone 3	Wyman 4	Municipal	Revenue	Revenue
			SVC		Newington			Support	Requirements	Requirements
	BECo	NEP	NEH	NEP	NU	NU	CMP	Total		Total
Hingham	$525	$8,078	$3,743	$2,006	$1,711	$3,522	$0	$19,586	$29,040	$48,626
Hull	$157	$2,406	$1,115	$698	$596	$1,331	$452	$6,754	$10,108	$16,862
Middleborough	$466	$7,159	$3,318	$2,131	$1,818	$3,947	$597	$19,435	$30,852	$50,287
Pascoag,RI	$100	$1,540	$714	$452	$386	$0	$0	$3,192	$6,549	$9,741
Concord	$524	$8,058	$3,734	$0	$0	$0	$0	$12,316	$0	$12,316
Ashburnham	$78	$1,196	$554	$276	$235	$1,073	$0	$3,413	$3,991	$7,404
Boylston	$88	$1,348	$625	$359	$306	$924	$187	$3,837	$5,200	$9,038
Danvers	$1,046	$16,082	$7,453	$4,708	$4,017	$9,189	$0	$42,496	$68,166	$110,662
Georgetown	$101	$1,553	$720	$405	$345	$728	$0	$3,852	$5,862	$9,714
Groton,MA	$116	$1,778	$824	$545	$465	$889	$0	$4,617	$7,891	$12,508
Holden	$322	$4,951	$2,294	$1,680	$1,434	$2,540	$0	$13,221	$24,329	$37,551
Hudson	$645	$9,915	$4,595	$7,084	$6,047	$3,694	$1,217	$33,197	$97,872	$131,069
Ipswich	$0	$0	$0	$451	$385	$2,126	$0	$2,962	$6,527	$9,489
Littleton,MA	$321	$4,938	$2,288	$463	$395	$1,875	$597	$10,877	$6,698	$17,575
Mansfield	$731	$11,244	$5,211	$3,344	$2,853	$5,531	$0	$28,914	$48,419	$77,334
Marblehead	$371	$5,704	$2,644	$572	$488	$5,402	$1,001	$16,181	$8,275	$24,456
Middleton	$204	$3,140	$1,455	$1,389	$1,185	$1,539	$363	$9,274	$20,104	$29,377
N. Attleboro	$475	$7,298	$3,382	$1,600	$1,365	$6,101	$597	$20,817	$23,163	$43,980
Paxton	$77	$1,177	$545	$342	$292	$1,141	$0	$3,573	$4,950	$8,523
Peabody	$1,239	$19,050	$8,829	$4,783	$4,081	$10,386	$0	$48,369	$69,254	$117,622
Rowley	$69	$1,058	$490	$0	$0	$0	$0	$1,617	$0	$1,617
Shrewsbury	$705	$10,841	$5,024	$2,436	$2,079	$8,127	$1,494	$30,706	$35,274	$65,980
Sterling	$0	$0	$0	$865	$738	$1,028	$0	$2,631	$12,522	$15,153
Templeton	$239	$3,669	$1,700	$816	$696	$2,448	$0	$9,566	$11,808	$21,374
Wakefield	$544	$8,368	$3,878	$1,638	$1,398	$7,190	$1,576	$24,593	$23,717	$48,310
W.Boylston	$223	$3,424	$1,587	$768	$655	$2,769	$0	$9,426	$11,115	$20,541
Chicopee	$1,376	$21,152	$9,803	$0	$0	$0	$0	$32,331	$0	$32,331
S.Hadley	$506	$7,773	$3,602	$1,444	$1,232	$20,133	$0	$34,691	$20,909	$55,600
Westfield	$1,105	$16,988	$7,873	$1,543	$1,316	$38,938	$2,601	$70,363	$22,337	$92,700
Total Support:	$12,352	$189,887	$88,001	$42,797	$36,518	$142,570	$10,682	$522,808	$614,930	$1,137,738

M:\SEABROOK\2009 PTO VOTING SHARES & REVENUE\PTF SUPPORT of Munis during 2009 WKBK_Amended 5.21.105/21/2010

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:	**21-May-10**
Revised on:	**N/A**
Revenue Requirements for (year):	**2009**
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	=	710,409	(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)		710,409	(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:	710,409	(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)	710,409	(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)	6,610,015	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)		6,610,015	
5	Accumulated Depreciation	(A)(1)(d)	3,089,135	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)		3,520,880	
10	Prepayments	(A)(1)(h)	9,170	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	124,620	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	33,854	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		3,688,524	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	295,082	Worksheet 2
15	Depreciation Expense	(B)	79,649	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)	62,079	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	2,767	*Worksheet 4, line 17 column 5*
20	Operation & Maintenance Expense	(G)	262,363	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	8,469	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)		710,409	

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**

(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) / 3,688,524) 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) / 3,688,524) + 0.0000000)* 0 / (1 - 0)

= 0.0000000

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

		(PTF)	
INVESTMENT BASE	$	3,688,524	From Worksheet 1
x Cost of Capital Rate		0.0800000	
= Investment Return and Income Taxes		295,082	To Worksheet 1

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	7,723,648	Directly Assigned	7,723,648		6,610,015	Line 1, Worksheet 5
2	General Plant	0	0.5385% (a)	0	85.5815%	0	Page 8B, line 29g
3	Total (line 1+2)			7,723,648		6,610,015	
4	Transmission Plant Held for Future Use	0		0	85.5815%	0	None known
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	3,609,583		3,609,583	85.5815%	3,089,135	Page 8A, line 31g less Page 16, line 31g
6	General Plant Accum.Depreciation	0	0.5385% (a)	0	85.5815%	0	Page 8B, line 29g less Page 17, line 29g
7	Total (line 5+6)			3,609,583		3,089,135	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	0	2.6184% (c)	0	85.5815%	0	None known
9	Accumulated Deferred Taxes (190)	0	2.6184% (c)	0	85.5815%	0	None known
10	Total (line 8+9)			0		0	
11	Transmission loss on Reacquired Debt	0	2.6184% (c)	0	85.5815%	0	None known
	Other Regulatory Assets						
12	FAS 106	0	0.5385% (a)	0	85.5815%	0	None known
13	FAS 109	0	2.6184% (c)	0	85.5815%	0	None known
14	Other Regulatory Liabilities (254.DK)	0	2.6184% (c)	0	85.5815%	0	
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments	409,213	2.6184% (a)	10,715	85.5815%	9,170	Page 10, line 26c
17	Transmission Materials and Supplies	5,561,223	2.6184% (a)	145,615	85.5815%	124,620	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)	FERC Form 1 Reference for col (1)
18	Cash Working Capital		
19	Operation & Maintenance Expense	262,363	Worksheet 1, Line 20
20	Administrative & General Expense	8,469	Worksheet 1, Line 21
21	Transmission Support Expense	0	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)	270,832	
23		0.125	x 45 / 360
24	Total (line 22 * line 23)	33,854	

(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	93,068		93,068	85.5815%	79,649	Page 16, line 31d
2	General Depreciation	0	0.5385% (a)	0	85.5815%	0	Page 17, line 29d
3	Total (line 1+2)			93,068		79,649	
4	Amortization of Loss on Reacquired Debt	0	2.6184% (c)	0	85.5815%	0	Page 12, line 28b
5	Amortization of Investment Tax Credits	0	2.6184% (c)	0	85.5815%	0	None known
	Property Taxes *						
6	Transmission Property Taxes	0		0	85.5815%	0	See below
7	General Property Taxes	2,770,325	2.6184% (c)	72,538	85.5815%	62,079	See below
8	Total (line 6+7)			72,538		62,079	
		281,863					
	Transmission Operation and Maintenance	PER INTERPRETATIVE GUIDANCE DOCUMENT SECTION II.G RULES FOR HGED					
9	Operation and Maintenance	306,565	B-2	306,565	0.855815	262,363	Page 40, line 50b
10	Transmission of Electricity by Others - #565	0		0	0.855815	0	Page 40, line 38b
11	Load Dispatching - #561	0		0	0.855815	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	306,565		306,565	85.5815%	262,363	
	Transmission Administrative and General						
14	Administrative and General	1,837,698	From 12/31/09 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)]	1,837,698	0.5385% *(a)*	9,896	85.5815%	8,469	
19	***PLUS** Property Insurance alloc. using Plant Allocation*	*0*	*2.6184% (c)*	0	85.5815%	0	
20	***PLUS** Regulatory Comm. Exp. (FERC Assessments)*	*0*	*2.6184% (c)*	0	85.5815%	0	
21	***PLUS** Trans. Related General Advertising Expense*	*0*	*2.6184% (c)*	0	85.5815%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*1,837,698*		*9,896*		*8,469*	
23	*Payroll Tax Expense*	*600,319*	*0.5385% (a)*	*3,233*	*85.5815%*	*2,767*	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	600,319	926-05
FICA/Medicare	0	926-06
MA Unemployment	0	
MA Universal Health	0	
Total	600,319	*To Line 23*

* Property Taxes

		Transmission	General	
a	Gross Plant	7,723,648	-	Worksheet 3, lines 1 & 2
b	Depr Reserve	3,609,583	0	Worksheet 3, lines 5 & 6
c = a - b	Net Book Value	4,114,065	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	6,610,015		MMWEC Share of FPL-Seabrook
2	Total Transmission Investment	7,723,648		MMWEC Share of FPL-Seabrook
3	Percent Allocation (Line 1/Line 2)	85.5815%		
	Transmission Wages and Salaries Allocation Factor			
4	Direct Transmission Wages and Salaries	38,224	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)	38,224		
7	Total Wages and Salaries	7,098,627	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)	7,098,627		
11	Percent Allocation (Line 6/Line 10)	0.5385%		
	Plant Allocation Factor			
12	Total Transmission Investment	11,899,418		Per MMWEC Accounting Records
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	0		
14	*= Revised Numerator (Line 12 + Line 13)*	11,899,418		
15	Total Plant in Service	454,455,751		Page 8B, line 30g
16	Percent Allocation (Line 14 / Line 15)	2.6184%		b

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

Sheet: Worksheet 7

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

Participant	PTF Supporting Facilities	FERC Form 1	TOTAL Revenues (a)	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)

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 2009	
Rates Effective for the Period:			June 2010	
Through:			May 2011	
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	$89,661,917	(a)	$106,294,986	(f)
Total of Attachment F - Section J - Support Revenue	$7,130,058	(b)	$0	(g)
Total of Attachment F - Section K - Support Expense	$963,053	(c)	$0	(h)
Total of Attachment F - Section (L through O)	($553,414)	(d)	($1,009,995)	(i)
Sub Total - Sum (A through I) - J + K + (L through O)	$82,941,498	(e)=(a)-(b)+(c)+(d)	$105,284,991	(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	N/A		$25,197,392	(k)
Annual True-up (per Attachment C to Attachment F Implementation Rule)	$578,247	(l)	($11,558,110)	(m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)	$83,519,745	(n)=(e)+(l)	$118,924,272	(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)			$202,444,017	(p) = (n) + (o)

New England Power Company
Transmission Revenue Requirements of PTF Facilities
2009 True-up

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

		PRE 97	POST 1996
1	**Transmission Revenue Requirements (as billed)**	$82,381,954	$116,469,252
2	True-up 2009 Actual Annual RR	$82,941,498	$105,284,991
3	(Over)/Under (Line 2 - Line 1)	559,544	(11,184,261)
4	Per Month (Line 3/12)	46,629	(932,022)
5	Total Rate Year (Over)/Under	$ 559,544	$ (11,184,261)

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

	Undercollection/(Overcollection)
Pre 97	$559,544
Post 96	($11,184,261)

Initial Billing Period	**PRE 97 Balance**	**POST 1996 Balance**	**FERC Monthly Interest Rate**	**PRE 97 Interest**	**POST 1996 Interest**
June 2009	$ 559,544	$ (11,184,261)	0.28%	$ 1,567	$ (31,316)
July 2009	561,111	(11,215,577)	0.28%	1,571	(31,404)
August 2009	561,111	(11,215,577)	0.28%	1,571	(31,404)
September 2009	561,111	(11,215,577)	0.27%	1,515	(30,282)
October 2009	565,768	(11,308,666)	0.28%	1,584	(31,664)
November 2009	565,768	(11,308,666)	0.27%	1,528	(30,533)
December 2009	565,768	(11,308,666)	0.28%	1,584	(31,664)
January 2010	570,464	(11,402,528)	0.28%	1,597	(31,927)
February 2010	570,464	(11,402,528)	0.25%	1,426	(28,506)
March 2010	570,464	(11,402,528)	0.28%	1,597	(31,927)
April 2010	575,085	(11,494,889)	0.27%	1,553	(31,036)
May 2010	575,085	(11,494,889)	0.28%	1,610	(32,186)
		Total Interest		**$ 18,704**	**$ (373,850)**
		True-Up		559,544	$ (11,184,261)
		Total TU & Int		**$ 578,247**	**$ (11,558,110)**

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 2009
Rates Effective for the Period:	June 2010
Through:	May 2011
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	$89,661,917	(a)	$106,294,986	(f)
Total of Attachment F - Section J - Support Revenue	$7,130,058	(b)	$0	(g)
Total of Attachment F - Section K - Support Expense	$963,053	(c)	$0	(h)
Total of Attachment F - Section (L through O)	($553,414)	(d)	($1,009,995)	(i)
Sub Total - Sum (A through I) - J + K + (L through O)	$82,941,498	(e)=(a)-(b)+(c)+(d)	$105,284,991	(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	N/A		$25,197,392	(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)	$82,941,498	(n)=(e) + (l)	$130,482,383	(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:			$213,423,880	(p) = (n) + (o)

New England Power Company
Annual Revenue Requirements of PTF Facilities
For Costs in 2009

PRE-1997

Shading denotes an input

Line No.			Attachment F Reference Section:	NEP	Reference
	I.	INVESTMENT BASE			
1		Transmission Plant	(A)(1)(a)	$337,679,354	Worksheet 3, line 1&2 column 5
2		General Plant	(A)(1)(b)	$1,670,184	Worksheet 3, line 3 column 5
3		Plant Held For Future Use	(A)(1)(c)	$262,135	Worksheet 3, line 5 column 5
4		Total Plant (Lines 1+2+3)		$339,611,673	
5		Accumulated Depreciation	(A)(1)(d)	$78,631,602	Worksheet 3, line 8 column 5
6		Accumulated Deferred Income Taxes	(A)(1)(e)	$70,740,108	Worksheet 3, line 11 column 5
7		Loss On Reacquired Debt	(A)(1)(f)	$252,665	Worksheet 3, line 12 column 5
8		Other Regulatory Assets	(A)(1)(g)	$15,663,973	Worksheet 3, line 16 column 5
9		Net Investment (Line 4-5-6+7+8)		$206,156,601	
10		Prepayments	(A)(1)(h)	$0	Worksheet 3, line 17 column 5
11		Materials & Supplies	(A)(1)(i)	$991,098	Worksheet 3, line 18 column 5
12		Cash Working Capital	(A)(1)(j)	$1,993,508	Worksheet 3, line 25 column 5
13		Total Investment Base (Line 9+10+11+12)		$209,141,207	
	II.	REVENUE REQUIREMENTS			
14		Investment Return and Income Taxes	(A)	$26,783,062	Worksheet 2
15		Depreciation Expense	(B)	$7,291,591	Worksheet 4, line 3, column 5
16		Amortization of Loss on Reacquired Debt	(C)	$74,805	Worksheet 4, line 4, column 5
17		Investment Tax Credit	(D)	($103,586)	Worksheet 4, line 5, column 5
18		Property Tax Expense	(E)	$5,345,921	Worksheet 4, line 6, column 5
19		Payroll Tax Expense	(F)	$500,293	Worksheet 4, line 22, column 5
20		Operation & Maintenance Expense	(G)	$8,769,297	Worksheet 4, line 11, column 5
21		Administrative & General Expense	(H)	$7,178,765	Worksheet 4, line 21, column 5
22		Transmission Related Integrated Facilities Charge	(I)	$33,821,768	Attachment 4, line 6
23		Transmission Support Revenue	(J)	($7,130,058)	Worksheet 6
24		Transmission Support Expense	(K)	$963,053	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)	($327,031)	Attachment 7
28		Transmission Rents Received from Electric Property	(O)	($226,383)	Attachment 6
29		Total Revenue Requirements (Line 14 thru 28)		$82,941,498	

New England Power Company
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	$410,350,000	35.48%	1.58%	0.56%	
PREFERRED STOCK	$1,111,700	0.10%	6.02%	0.01%	0.01%
COMMON EQUITY	$745,076,320	64.42%	11.64%	7.50%	7.50%
TOTAL INVESTMENT RETURN	$1,156,538,020	100.00%		8.07%	7.51%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0807

(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)

= (0.0751 +(($103,586) + $228,873) / $209,141,207) x 0.35) / (1 - 0.35)

= 0.0407610

(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)

= (0.0751 +(($103,586) + $228,873) / $209,141,207) + 0.0407610)* 0.053641 / (1 - 0.053641)

= 0.0066011

(a)+(b)+(c) Cost of Capital Rate = 0.1280621

	(PTF)	
INVESTMENT BASE	$209,141,207	From Worksheet 1
x Cost of Capital Rate	0.1280621	
= Investment Return and Income Taxes	$26,783,062	To Worksheet 1

Source: Attachment 2

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			$0		$350,766,082	Attachment 1, Page 1
2	Less: Plant Assoc. HVDC Leases					($13,086,728)	Attachment 1, Page 2
3	General Plant	$6,563,943	99.7633% (a)	$6,548,406	25.5052%	$1,670,184	FERC Form 1 Page 207.99g
4	Total (line 1+2+ 3)			$6,548,406		$339,349,538	
5	Transmission Plant Held for Future Use	$1,027,771		$1,027,771	25.5052%	$262,135	FERC Form 1 Page 214.2,4,9
	Transmission Accumulated Depreciation						
6	Transmission Accum. Depreciation	$303,640,607		$303,640,607	25.5052%	$77,444,144	FERC Form 1 Page 219.25
7	General Plant Accum.Depreciation	$4,666,793	99.7633% (a)	$4,655,747	25.5052%	$1,187,458	FERC Form 1 Page 219.28
8	Total (line 6+ 7)			$308,296,354		$78,631,602	
	Transmission Accumulated Deferred Taxes						
9	Accumulated Deferred Taxes (281-283)	-$430,463,140	99.2163%	($427,089,600)	25.5052%	($108,930,057)	FERC Form 1 Page 113.62-64
10	Accumulated Deferred Taxes (190)	$150,916,705	99.2163%	$149,733,971	25.5052%	$38,189,949	FERC Form 1 Page 111.82
11	Total (line 9+ 10)			($277,355,629)		($70,740,108)	
12	Transmission Loss on Reacquired Debt	$990,643	100.0000%	$990,643	25.5052%	$252,665	FERC Form 1 Page 111.81c
	Other Regulatory Assets						
13	FAS 106	$0	99.7633% (a)	$0	25.5052%	$0	
14	FAS 109 (Asset Account 182.3)	$61,414,823	100.0000%	$61,414,823	25.5052%	$15,663,973	FERC Form 1 Page 232.7f
15	FAS 109 (Liability Account 254)	$0	100.0000%	$0	25.5052%	$0	
16	Total (line 13+14+ 15)	$61,414,823		$61,414,823		$15,663,973	
17	Transmission Prepayments	$0	99.7633% (a)	$0	25.5052%	$0	FERC Form 1 Page 111.57c
18	Transmission Materials and Supplies	$3,885,867		$3,885,867	25.5052%	$991,098	FERC Form 1 Page 227.8c
19	Cash Working Capital						
20	Operation & Maintenance Expense					$8,769,297	Worksheet 1, Line 20
21	Administrative & General Expense					$7,178,765	Worksheet 1, Line 21
22	Transmission Support Expense					$0	Worksheet 6
23	Subtotal (line 20+21+22)					$15,948,062	
24						0.1250	x 45 / 360
25	Total (line 23 * line 24)					$1,993,508	

(a) Worksheet 5 Line 11
(b) Worksheet 5 Line 3

New England Power Company

Shading denotes an input

Line (1) No.		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	$28,239,845			$28,239,845	25.5052%	$7,202,629	FERC Form 1 Page 336.7b
2	General Depreciation	$349,629	99.7633%	(a)	$348,801	25.5052%	$88,962	FERC Form 1 Page 336.10b
3					$28,588,646		$7,291,591	
4	Amortization of Loss on Reacquired Debt	$293,292	100.0000%		$293,292	25.5052%	$74,805	FERC Form 1 Page 117.64c
5	Amortization of Investment Tax Credits	$406,136	100.0000%		$406,136	25.5052%	$103,586	FERC Form 1 Page 266.8f - Footnote (f)
6	Property Taxes	$20,960,123	100.0000%		$20,960,123	25.5052%	$5,345,921	FERC Form 1 Page 263.10,17,23,28i - Footnote (e)
	Transmission Operation and Maintenance							
7	Operation and Maintenance	$62,195,739			$62,195,739	25.5052%	$15,863,148	FERC Form 1 Page 321.112b
8	Transmission of Electricity by Others - #565	$15,883,436			$15,883,436	25.5052%	$4,051,102	FERC Form 1 Page 321.96b
9	Load Dispatching - #561 (excl #561.3)	$11,929,915			$11,929,915	25.5052%	$3,042,749	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	$34,382,388			$34,382,388	25.5052%	$8,769,297	
	Transmission Administrative and General							
12	Total Administrative and General	$29,814,013						FERC Form 1 Page 323.197b
13	less Property Insurance (#924)	-$440,927						FERC Form 1 Page 323.185b
14	less Regulatory Commission Expenses (#928)	$4,241,188						FERC Form 1 Page 323.189b
15	less General Advertising Expense (#930.1)	$24,704						FERC Form 1 Page 323.191b
16	Subtotal [line 12 minus (13 thru 15)]	$25,989,048	99.7633%	(a)	$25,927,532	25.5052%	$6,612,869	
17	PLUS Property Insurance alloc. using Plant Allocatior	-$440,927	99.2163%	(c)	-$437,471	25.5052%	-$111,578	Line 13
18	PLUS Regulatory Comm. Exp.	$2,608,204	99.2163%	(c)	$2,587,764	25.5052%	$660,014	Attachment 5 Line 6
19	PLUS Specifically identifed T rans. Related General Advertising Expense	$24,704			$24,704	25.5052%	$6,301	Line 15
20	PLUS Specifically identifed Trans. Related Regulatory Expense	$43,753			$43,753	25.5052%	$11,159	FERC Form 1 Page 350.18c
21	Total A&G [line 16 + (17 thru 20)]	$28,224,782			$28,146,282		$7,178,765	
22	Payroll Tax Expense	$1,966,189	99.7633%	(a)	$1,961,535	25.5052%	$500,293	FERC Form 1 Page 263.3,4i - Footnote (d)

(a) Worksheet 5 Line 11
(b) Worksheet 5 Line 3
(c) Worksheet 5 Line 16

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

Federal Unemployment	$13,994
FICA	$1,952,195
Payroll Taxes	$0
State Unemployment	$0
Total	$1,966,189

(e) Property Taxes FF1, Page 263i

Massachusetts	$17,745,431
New Hampshire	$2,340,263
Vermont	$730,106
Maine	$0
Rhode Island	$144,323
Connecticut	$0
	$20,960,123

(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.		NEP	Source Reference
	PTF Transmission Plant Allocation Factor		
1	PTF Transmission Investment	$350,766,082	Attachment 1, Page 1
2		$1,375,270,230	FERC Form 1 Page 207.58g - Page 200.4b
3	Percent Allocation (Line 1/Line 2)	25.5052%	
	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	$22,154,668	General Ledger Query
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	$22,154,668	
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	$22,207,232	General Ledger Query
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	$22,207,232	
11	Percent Allocation (Line 6/Line 10)	99.7633%	
	Plant Allocation Factor		
12	Total Transmission Investment	$1,375,270,230	Line 2
13	plus Transmission-Related General Plant	$6,548,406	Worksheet 3, Line 3, Column 3
14	= Revised Numerator (Line 12 + Line 13)	$1,381,818,636	
15	Total Plant in Service	$1,392,733,917	FERC Form 1 Page 207.104g - Page 200.4b
16	Percent Allocation (Line 14 / Line 16)	99.2163%	

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	14092582		
	345 kV Golden Hills -Mystic 389 (x&y) line	Contract Suspended Oct. 1997		$0
	West Medway 345 kV breaker	Pg 332 Line 6 Col (g)		$0
	115 kV Millbury-Medway 201 line	Pg 332 Line 2 Col (g)		$9,334
	HQ Phase II - AC in MA	Pg 332 Line 5 Col (g)		$115,229
	345 kV "stabilizer" 342 line	Pg 332 Line 3 Col (g)		$69,187
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line	Pg 332 Lines 12 & 13 Col (g)		$19,462
	345 kV Jordan Rd - Canal 342 line			
CEC	**Second Canal line**	Pg 332 Line 4 Col (g)		$47,040
	345 kV Pilgrim-Bridgewater - 355 line			$0
	345 kV Myles Standish - Canal 342 line			$0
	Bell Rock Road	Page 330.5 Line 12	-$4,408	
CMP	**345 kV Buxton-South Gorham 386 line**	Page 332.1, Line 4		$0
	115 kV Wyman 164-167 lines	Pg 332.1 Line 3 Col (g)		$0
	115 kV Maine Yankee transmission			
NEP	345 kV Carver - Walpole 331 line		$0	
	345 kV Medway - Bridgewater 344 Line	Pg 330.5, Line 11	$166,069	
	Northern Rhode Island transmission	Reflect in Integr. Fac. Chg. Wksh1	N/A	N/A
NEP	**Chester SVC**	Tx Billing		$692,801
	Fitchburg Support	See Attachment 9		$0
	MWRA Transmission (MDC)	Contract		$10,000
VT Elec Co.	**Comerford 115 kV Substation**	Page 330.1 Line 12	$41,705	
	Boston-Edison [345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line]	Page 330 Line 4	$854,688	
	Boston-Edison [115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line]	Page 330 Line 3	$110,499	
	Public Service Co. -Moore 115 kV Substation	Page 330.1 Line 5	$13,319	
	HQ Phase II - AC in MA	Page 330 Line 11	$5,099,585	
	Boston Edison -345 kV Golden Hills-Mystic 349 line	Page 330 Line 2	$425,327	
	345 kV NH/MA border-Tewksbury 394 line (Seabrook)	Page 330.1 Line 8	$423,274 *	
NU	**PSNH 345 kV 363, 369 and 394 Seabrook lines**	Page 332 Line 11		$0
	Fairmont 115 kV Substation			
	345 kV Millstone-Manchester 310 line	Page 332.1 Line 5		$0
	UI Substations			
	Black Pond			
		Total =	$7,130,058	$963,053

* 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	$	2,821,824
Revised @ 15% per FERC Order	$	423,274
FF1 Adjustment	$	2,398,550

Shading denotes an input

New England Power Company
2009 Informational Filing
PTF Plant Allocation

				Percent Pre/Post
1	2008	Pre-1997 PTF Transmission Plant	$352,396,942	
2	2008	Post-1996 PTF Transmission Plant	$502,643,379	
3	2009	Additions/Retirements	$135,881,859	
4	2009	Pre-1997 PTF Transmission Plant	$350,766,082	35.40%
5	2009	Post-1996 PTF Transmission Plant	$640,156,098	64.60%
6	2009	Total PTF Transmission Plant	$990,922,180	100.00%

Sources:

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

Shading denotes an input

GROSS PLANT ASSOC. WITH HVDC LEASES
2009

LINE NO	NHH/NEH	(HVDC) 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
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

		2009
1	Total Current Year Book Depreciation on Equity AFUDC	$900,396
2	Less: Specifically Identified Transmission-Related	
	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
	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
		$513,021
3	Total Unidentified Book Depreciation on Equity AFUDC	$387,375
4	Plant Allocator Factor	99.2163%
5	Allocated Transmission Related Book Depreciation on Equity AFUDC	$384,339
6	Plus: Specifically Identified Transmission-Related Equity AFUDC	$513,021
7	Total Transmission-Related Equity AFUDC	$897,360
8	Pre-97 PTF Allocation Factor	25.5052%
9	Transmission-Related Equity AFUDC	$228,873

Sources:

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

Shading denotes an input

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

		Narragansett 2009	MECO 2009
1	Total Integrated Facilities Charges	$42,294,362	$7,830,887
2	Total 2009 PTF Property	$172,481,172	$19,014,465
3	Total Transmission Plant in 2009	$239,329,792	$44,568,938
4	NECO or MECO PTF Plant Allocator	72.07%	42.66%
5	PTF Related Integrated Facilities Charge	$30,480,874	$3,340,895
6	**Total Integrated Facilities**		**$33,821,768**

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 2009 Regulatory Commission Expense

Line No.		2009	Source
1	Total Regulatory Commission Expense - NEP	$4,241,188	FERC Form1 Page 350.46d
2	Less: New Hampshire PUC Assessment	$54,748	FERC Form1 Page 350.2d
3	Less: Mass Emergency Fund	$249,867	FERC Form1 Page 350.7d
4	Less Mass DPU Special Assessment	$0	FERC Form1 Page 350.8d
5	Less: Utility Expenses	$1,328,369	FERC Form1 Page 350.46c
6	Total Federal Assessments	$2,608,204	Line 1 - (Line 2-5)

Transmission Rents Received from Electric Property
New England Power Company

	2009
Revenues	$887,595
Plant Allocation Factor	100.00%
Transmission Allocated	$887,595
PTF Allocation	25.5052%
Total PTF Revenue	$226,383

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

Revenue for Short-Term Transmission Service under the NEPOOL Tariff

New England Power Company

	2009
Revenues	$923,870
Pre-97 PTF Percent	35.3979%
Total Pre-97 PTF Revenue	$ 327,031

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 2009
Rates Effective for the Period:		June 2010
Through:		May 2011
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	$89,661,917	(a)	$106,294,986	(f)
Total of Attachment F - Section J - Support Revenue	$7,130,058	(b)	$0	(g)
Total of Attachment F - Section K - Support Expense	$963,053	(c)	$0	(h)
Total of Attachment F - Section (L through O)	($553,414)	(d)	($1,009,995)	(i)
Sub Total - Sum (A through I) - J + K + (L through O)	$82,941,498	(e)=(a)-(b)+(c)+(d)	$105,284,991	(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	N/A		$25,197,392	(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)	$82,941,498	(n)=(e)+(l)	$130,482,383	(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)			$213,423,880	(p) = (n) + (o)

New England Power Company
Annual Revenue Requirements of PTF Facilities
For Costs in 2009

POST-1996

Shading denotes an input

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	NEP	Reference
1	Transmission Plant	(A)(1)(a)	$640,156,098	Worksheet 3, line 1&2 column 5
2	General Plant	(A)(1)(b)	$3,048,132	Worksheet 3, line 3 column 5
3	Plant Held For Future Use	(A)(1)(c)	$478,404	Worksheet 3, line 5 column 5
4	Total Plant (Lines 1+2+3)		$643,682,634	
5	Accumulated Depreciation	(A)(1)(d)	$143,504,862	Worksheet 3, line 8 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	$129,102,666	Worksheet 3, line 11 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	$461,122	Worksheet 3, line 12 column 5
8	Other Regulatory Assets	(A)(1)(g)	$28,587,188	Worksheet 3, line 16 column 5
9	Net Investment (Line 4-5-6+7+8)		$400,123,416	
10	Prepayments	(A)(1)(h)	$0	Worksheet 3, line 17 column 5
11	Materials & Supplies	(A)(1)(i)	$1,808,782	Worksheet 3, line 18 column 5
12	Cash Working Capital	(A)(1)(j)	$3,638,207	Worksheet 3, line 25 column 5
13	Total Investment Base (Line 9+10+11+12)		$405,570,405	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	$53,264,992	Worksheet 2
15	Depreciation Expense	(B)	$13,307,357	Worksheet 4, line 3, column 5
16	Amortization of Loss on Reacquired Debt	(C)	$136,521	Worksheet 4, line 4, column 5
17	Investment Tax Credit	(D)	($189,047)	Worksheet 4, line 5, column 5
18	Property Tax Expense	(E)	$9,756,455	Worksheet 4, line 6, column 5
19	Payroll Tax Expense	(F)	$913,049	Worksheet 4, line 22, column 5
20	Operation & Maintenance Expense	(G)	$16,004,211	Worksheet 4, line 11, column 5
21	Administrative & General Expense	(H)	$13,101,447	Worksheet 4, line 21, column 5
22	Transmission Related Integrated Facilities Charge	(I)	$0	Attachment 4, line 6
23	Transmission Support Revenue	(J)	$0	Worksheet 6
24	Transmission Support Expense	(K)	$0	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)	($596,840)	Attachment 7
28	Transmission Rents Received from Electric Property	(O)	($413,155)	Attachment 6
29	Total Revenue Requirements (Line 14 thru 28)		$105,284,991	

New England Power Company
Forecasted Transmission Revenue Requirements of PTF Facilities

POST-1996

Shading denotes an input

Line No.	I. FORECASTED TRANSMISSION REVENUE REQUIREMENTS	Period	Attachment F Reference *Section:*	NEP	Reference
1	Forecasted Transmission Plant Additions	**2009**	Appendix C	$151,750,000	
2	Carrying Charge Factor		Appendix C	16.60%	
3	Total Forecasted Revenue Requirements (Lines 1*2)			$25,197,392	

Line No.	II. CARRYING CHARGE FACTOR	Attachment F Reference	NEP	Reference
4	Investment Return and Income Taxes	(A)	$53,264,992	Summary, line 14
5	Depreciation Expense	(B)	13,307,357	Summary, line 15
6	Amortization of Loss on Reacquired Debt	(C)	136,521	Summary, line 16
7	Investment Tax Credit	(D)	(189,047)	Summary, line 17
8	Property Tax Expense	(E)	9,756,455	Summary, line 18
9	Payroll Tax Expense	(F)	913,049	Summary, line 19
10	Operation & Maintenance Expense	(G)	16,004,211	Summary, line 20
11	Administrative & General Expense	(H)	13,101,447	Summary, line 21
12	Total Expenses (Lines 4 thru 11)		$106,294,986	
13	PTF Transmission Plant	(A)(1)(a)	$640,156,098	Summary, line 1
14	Carrying Charge Factor (Lines 12/13)		16.60%	

New England Power Company
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	$410,350,000	35.48%	1.58%	0.56%	
PREFERRED STOCK	$1,111,700	0.10%	6.02%	0.01%	0.01%
COMMON EQUITY	$745,076,320	64.42%	11.64%	7.50%	7.50%
TOTAL INVESTMENT RETURN	$1,156,538,020	100.00%		8.07%	7.51%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0807

(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)

= (0.0751 +(($189,047) + $417,701) / $405,570,405) x 0.35) / (1 - 0.35)

= 0.0407420

(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)

= (0.0751 +(($189,047) + $417,701) / $405,570,405) + 0.0407420)* 0.053641 / (1 - 0.053641)

= 0.0065980

(a)+(b)+(c) Cost of Capital Rate = 0.1280400

	(PTF)	
INVESTMENT BASE	$405,570,405	From Worksheet 1
x Cost of Capital Rate	0.1280400	
= Investment Return and Income Taxes	$51,929,235	To Worksheet 1

Source: Attachment 2

Post 2003 PTF Investment Base w/ Incremental 100 bps:

Plant		$	219,665,153	From Attachment 1
Accum. Depreciation		$	50,562,703	From Worksheets 3 & 5
Accum. Deferred		$	45,823,731	From Worksheets 3 & 5
Total Post-2003 Investment		$	123,278,718	Calculated
Incremental ROE:	1.00%		0.00644	Calculated
FIT:			0.00347	Per Attach. F
State Income Taxes:			0.00056	Per Attach. F
Cost of Capital Rate			0.01047	
Incremental Return and Taxes on Post-2003 PTF Investment		$	1,291,040	

NEEWS PTF Investment Base w/ Incremental 125 bps:

Plant		$	10,856,783	PowerPlant Report
Accum. Depreciation		$	2,397,027	From Worksheets 3 & 5
Accum. Deferred		$	2,172,367	From Worksheets 3 & 5
Total NEEWS Investment		$	6,287,389	Calculated
Incremental ROE:	1.25%		0.00438	Calculated
FIT:			0.00236	Per Attach. F
State Income Taxes:			0.00038	Per Attach. F
Cost of Capital Rate			0.00711	
Incremental Return and Taxes on NEEWS PTF Investment		$	44,718	

NEEWS Allocation Factor

Total Trans Investment	$1,375,270,230
Total NEEWS In-Service	$10,856,783
For Accum Depreciation	0.7894%
Post-2003 PTF Allocation Factor	0.7894%
Plant Allocation Factor	0.992163
For Accum Deferred	0.7832%

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			$0		$640,156,098	Attachment 1, Page 1
2	Less: Plant Assoc. HVDC Leases					$0	Attachment 1, Page 2
3	General Plant	$6,563,943	99.7633% (a)	$6,548,406	46.5477%	$3,048,132	FERC Form 1 page 207.99
4	Total (line 1+2+ 3)			$6,548,406		$643,204,230	
5	Transmission Plant Held for Future Use	$1,027,771		$1,027,771	46.5477%	$478,404	FERC Form 1 page 214.2,4,9
	Transmission Accumulated Depreciation						
6	Transmission Accum. Depreciation	$303,640,607		$303,640,607	46.5477%	$141,337,719	FERC Form 1 page 219.25
7	General Plant Accum.Depreciation	$4,666,793	99.7633% (a)	$4,655,747	46.5477%	$2,167,143	FERC Form 1 Page 219.28
8	Total (line 6+ 7)			$308,296,354		$143,504,862	
	Transmission Accumulated Deferred Taxes						
9	Accumulated Deferred Taxes (281-283)	-$430,463,140	99.2163%	($427,089,600)	46.5477%	($198,800,386)	FERC Form 1 page 113.62-64
10	Accumulated Deferred Taxes (190)	$150,916,705	99.2163%	$149,733,971	46.5477%	$69,697,720	FERC Form 1 page 111.82
11	Total (line 9+ 10)			($277,355,629)		($129,102,666)	
12	Transmission Loss on Reacquired Debt	$990,643	100.0000%	$990,643	46.5477%	$461,122	FERC Form 1 Page 111.81c
	Other Regulatory Assets						
13	FAS 106	$0	99.7633% (a)	$0	46.5477%	$0	
14	FAS 109 (Asset Account 182.3)	$61,414,823	100.0000%	$61,414,823	46.5477%	$28,587,188	FERC Form 1 Page 232.7f
15	FAS 109 (Liability Account 254)	$0	100.0000%	$0	46.5477%	$0	
16	Total (line 13+14+ 15)	$61,414,823		$61,414,823		$28,587,188	
17	Transmission Prepayments	$0	99.7633% (a)	$0	46.5477%	$0	FERC Form 1 Page 111.57c
18	Transmission Materials and Supplies	$3,885,867		$3,885,867	46.5477%	$1,808,782	FERC Form 1 Page 227.8c
19	Cash Working Capital						
20	Operation & Maintenance Expense					$16,004,211	Worksheet 1, Line 20
21	Administrative & General Expense					$13,101,447	Worksheet 1, Line 21
22	Transmission Support Expense					$0	Worksheet 6
23	Subtotal (line 20+21+22)					$29,105,658	
24						0.1250	x 45 / 360
25	Total (line 23 * line 24)					$3,638,207	

(a) Worksheet 6 Line 11
(b) Worksheet 6 Line 3

New England Power Company

Shading denotes an input

Line (1) No.		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	$28,239,845		$28,239,845	46.5477%	$13,144,998	FERC Form 1 Page 336.7b
2	General Depreciation	$349,629	99.7633% (a)	$348,801	46.5477%	$162,359	FERC Form 1 Page 336.10b
3	Total (line 1+2)			$28,588,646		$13,307,357	
4	Amortization of Loss on Reacquired Debt	$293,292	100.0000%	$293,292	46.5477%	$136,521	FERC Form 1 Page 117.64c
5	Amortization of Investment Tax Credits	$406,136	100.0000%	$406,136	46.5477%	$189,047	FERC Form 1 Page 266.8f - Footnote (f)
6	Property Taxes	$20,960,123	100.0000%	$20,960,123	46.5477%	$9,756,455	FERC Form 1 Page 263.10,17,23,28i - Footnote (e)
	Transmission Operation and Maintenance						
7	Operation and Maintenance	$62,195,739		$62,195,739	46.5477%	$28,950,686	FERC Form 1 Page 321.112b
8	Transmission of Electricity by Others - #565	$15,883,436		$15,883,436	46.5477%	$7,393,374	FERC Form 1 Page 321.96b
9	Load Dispatching - #561 (excl #561.3)	$11,929,915		$11,929,915	46.5477%	$5,553,101	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	$34,382,388		$34,382,388	46.5477%	$16,004,211	
	Transmission Administrative and General						
12	Total Administrative and General	$29,814,013					FERC Form 1 Page 323.197b
13	less Property Insurance (#924)	-$440,927					FERC Form 1 Page 323.185b
14	less Regulatory Commission Expenses (#928)	$4,241,188					FERC Form 1 Page 323.189b
15	less General Advertising Expense (#930.1)	$24,704					FERC Form 1 Page 323.191b
16	Subtotal [line 12 minus (13 thru 15)]	$25,989,048	99.7633% (a)	$25,927,532	46.5477%	$12,068,670	
17	PLUS Property Insurance alloc. using Plant Allocator	-$440,927	99.2163% (c)	-$437,471	46.5477%	-$203,633	Line 13
18		$2,608,204	99.2163% (c)	$2,587,764	46.5477%	$1,204,545	Attachment 5 Line 6
19	PLUS Specifically identifed T rans. Related General Advertising Expense	$24,704		$24,704	46.5477%	$11,499	Line 15
20	PLUS Specifically identified Trans. Related Regulatory Expense	$43,753		$43,753	46.5477%	$20,366	FERC Form 1 Page 350.18c
21	Total A&G [line 16 + (17 thru 20)]	$28,224,782		$28,146,282		$13,101,447	
22	Payroll Tax Expense	$1,966,189	99.7633% (a)	$1,961,535	46.5477%	$913,049	FERC Form 1 Page 263.3,4i - Footnote (d)

(a) Worksheet 6, Line 11
(b) Worksheet 6 Line 3
(c) Worksheet 6 Line 16

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

Federal Unemployment	$13,994
FICA	$1,952,195
Payroll Taxes	$0
State Unemployment	$0
Total	$1,966,189

(e) Property Taxes FF1, Page 263i

Massachusetts	$17,745,431
New Hampshire	$2,340,263
Vermont	$730,106
Maine	$0
Rhode Island	$144,323
Connecticut	$0
	$20,960,123

(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.		NEP	Source Reference
	PTF Transmission Plant Allocation Factor		
1	PTF Transmission Investment	$640,156,098	Attachment 1, Page 1
2	Total Transmission Investment	$1,375,270,230	FERC Form 1 Page 207.58g - Page 200.4b
3	Percent Allocation (Line 1/Line 2)	46.5477%	
	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	$22,154,668	General Ledger Query
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	$22,154,668	
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	$22,207,232	General Ledger Query
10	Total Wages and Salaries net of A&G (Line 7 - 8 + 9)	$22,207,232	
11	Percent Allocation (Line 6/Line 10)	99.7633%	
	Plant Allocation Factor		
12	Total Transmission Investment	$1,375,270,230	Line 2
13	plus Transmission-Related General Plant (Line 2 of Wkst. 3)	$6,548,406	Worksheet 3, Line 3, Column 3
14	= Revised Numerator (Line 12 + Line 13)	$1,381,818,636	
15	Total Plant in Service	$1,392,733,917	FERC Form 1 Page 207.104g - Page 200.4b
16	Percent Allocation (Line 14 / Line 16)	99.2163%	
	Post-2003 PTF Allocation Factor		
17	Total Post-2003 PTF Investment	$ 229,012,126	Attachment 1 Line 7
18	Total Transmission Investment	$1,375,270,230	Line 2
19	Percent Allocation (Line 17/Line 18) for Post-2003 to Total Tx	16.6522%	
20	Total Invst in Tx Plant/Total Plant in Serv *		
21	Post-2003 PTF Tx Plant/Total Invst in Tx Plant	16.5217%	Line 19 * Line 16

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			$0
	West Medway 345 kV breaker	Page 332 Line 6 Column (g)		$0
	115 kV Millbury-Medway 201 line	Page 332 Line 2 Column (g)		$0
	HQ Phase II - AC in MA	Page 332 Line 5 Column (g)		$0
	345 kV "stabilizer" 342 line	Page 332 Line 3 Column (g)		$0
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line	Page 332 Line 4 Column (g)		$0
	345 kV Jordan Rd - Canal 342 line			
CEC	**Second Canal line**	Page 332 Line 7 Column (g)		$0
	345 kV Pilgrim-Bridgewater - 355 line			$0
	345 kV Myles Standish - Canal 342 line			$0
	Bell Rock Road		$0	$0
CMP	**345 kV Buxton-South Gorham 386 line**			$0
	115 kV Wyman 164-167 lines	Page 332.1 Line 3		$0
	115 kV Maine Yankee transmission			
EUA	345 kV Carver - Walpole 331 line		$0	
	345 kV Medway - Bridgewater 344 Line		$0	
	Northern Rhode Island transmission		N/A	N/A
NEP	**Chester SVC**			$0
	Fitchburg Support			$0
	MWRA Transmission			$0
	Comerford 115 kV Substation	Page 330.1 Line 12	$0	
	Boston-Edison [345 kV Sandy-Tewksbury 337 line			
	345 kV Tewksbury-Woburn 338 line]	Page 330 Line 4	$0	
	Boston-Edison [115 kV Tewksbury - Woburn M139 line			
	115 kV Tewksbury - Woburn N140 line]	Page 330 Line 3	$0	
	Public Service Co. -Moore 115 kV Substation	Page 330.1 Line 5	$0	
	HQ Phase II - AC in MA	Page 300 Line 10	$0	$0
	Boston Edison -345 kV Golden Hills-Mystic 349 line	Page 300 Line 2	$0	
	345 kV NH/MA border-Tewksbury 394 line	Page 300.1 Line 8	$0	$0
	115 kV Read - Washington V148 line	Page 300.1 Line 3	$0	$0
NU	**PSNH 345 kV 363, 369 and 394 Seabrook lines**	Page 332 Line 11 & Montuap Fin		$0
	Fairmont 115 kV Substation			
	345 kV Millstone-Manchester 310 line	Page 332.1 Line 5		$0
	UI Substations			
	Black Pond			
		Total =	$0	$0

Attachment 1

New England Power Company
2009 Informational Filing
PTF Plant Allocation

				Percent Pre/Post
1	2008	Pre-1997 PTF Transmission Plant	$352,396,942	
2	2008	Post-1996 PTF Transmission Plant	$502,643,379	
3	2009	Additions/Retirements	$135,881,859	
4	2009	Pre-1997 PTF Transmission Plant	$350,766,082	35.40%
5	2009	Post-1996 PTF Transmission Plant	$640,156,098	64.60%
6	2009	Total PTF Transmission Plant	$990,922,180	100.00%
7	2009	Post-2003 PTF Transmission Plant	$229,012,126	

Sources:

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

Shading denotes an input

GROSS PLANT ASSOC. WITH HVDC LEASES
2009

LINE NO	NHH/NEH	(HVDC) 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

		2009
1	Total Current Year Book Depreciation on Equity AFUDC	$900,396
2	Less: Specifically identified Transmission-Related	
	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
	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
		$513,021
3	Total unidentified Book Depreciation on Equity AFUDC	$387,375
4	Plant Allocator Factor	99.2163%
5	Allocated Transmission Related Book Depreciation on Equity AFUDC	$384,339
6	Plus: Specifically Identified Transmission-Related Equity AFUDC	$513,021
7	Total Transmission-Related Equity AFUDC	$897,360
8	Post-96 PTF Allocation Factor	46.5477%
9	Transmission-Related Equity AFUDC	$417,701

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

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

		Narragansett 2009	MECO 2009
1	Total Integrated Facilities Charges	$0	$0
2	Total 2009 PTF Property	$0	$0
3	Total Transmission Plant in 2009	$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 2009 Regulatory Commission Expense

Line No.		2009	Source
1	Total Regulatory Commission Expense - NEP	$4,241,188	FERC Form1 Page 350.46d
2	Less: New Hampshire PUC Assessment	$54,748	FERC Form1 Page 350.2d
3	Less: Mass Emergency Fund	$249,867	FERC Form1 Page 350.7d
4	Less Mass DPU Special Assessment	$0	FERC Form1 Page 350.8d
5	Less: Utility Expenses	$1,328,369	FERC Form1 Page 350.46c
6	Total Federal Assessments	$2,608,204	Line 1 - (Line 2-5)

Attachment 6

Transmission Rents Received from Electric Property
New England Power Company

	2009
Revenues	$887,595
Plant Allocation Factor	100.00%
Transmission Allocated	$887,595
PTF Allocation	46.5477%
Total PTF Revenue	$413,155

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

Revenue for Short-Term Transmission Service under the NEPOOL Tariff

New England Power Company

	2009
Revenues	$923,870
Post-96 PTF Percent	64.6021%
Total Post-96 PTF Revenue	$596,840

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

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

Submitted on:	18-May-10
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	= 96,001,325	(a)	402,617,687	(g)
Total of Attachment F - Section J - Support Revenue	1,834,559	(b)	0	(h)
Total of Attachment F - Section K - Support Expense	3,330,896	(c)	0	(i)
Total of Attachment F - Section (L through O)	(3,988,627)	(d)	10,227,275	(j)
Sub Total - Sum (A through I) - J + K + (L through O)	93,509,035	(e)=(a)-(b)+(c)+(d)	412,844,962	(k)=(g)-(h)+(i)+(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)	N/A	(f)	23,465,000	(l)
Annual True-up (per Attachment C to Attachment F Implementation Rule)	4,275,134	(m)	7,805,586	(n)
Adjusted Sub Total (Sub Total + True-up)	97,784,169	(o) = (e)+(f)+(m)	444,115,548	(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)			541,899,717	(q) = (o) + (p)

Northeast Utilities System Companies'
Annual Revenue Requirements of PTF Facilities
for costs in 2009
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,3B,3C line 1
2	General Plant	(A)(1)(b)	7,908,318	7,386,441	2,404,058	17,698,817	w/s 3A,3B,3C line 2
3	Plant Held For Future Use	(A)(1)(c)	5,289,319	1,204,503	5,240,803	11,734,625	w/s 3A,3B,3C line 4
4	Total Plant (Lines 1+2+3)		401,035,500	105,335,846	73,275,548	579,646,894	
5	Accumulated Depreciation	(A)(1)(d)	56,802,420	22,171,235	19,999,998	98,973,653	w/s 3A,3B,3C 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,3B,3C line 10
7	Loss On Reacquired Debt	(A)(1)(f)	849,771	465,911	34,994	1,350,676	w/s 3A,3B,3C line 11
8	Other Regulatory Assets	(A)(1)(g)	3,012,177	630,755	60,830	3,703,762	w/s 3A,3B,3C line 15
9	Net Investment (Line 4-5-6+7+8)		323,510,656	70,972,041	43,720,939	438,203,636	
10	Prepayments	(A)(1)(h)	851,000	1,767,821	1,725,380	4,344,201	w/s 3A,3B,3C line 16
11	Materials & Supplies	(A)(1)(i)	2,545,285	775,392	2,029,272	5,349,949	w/s 3A,3B,3C line 17
12	Cash Working Capital	(A)(1)(j)	1,517,674	671,001	457,113	2,645,788	w/s 3A,3B,3C line 24
13	Total Investment Base (Line 9+10+11+12)		328,424,615	74,186,255	47,932,704	450,543,574	
	II. REVENUE REQUIREMENTS						
14	Investment Return and Income Taxes	(A)	42,575,194	8,655,867	5,990,869	57,221,930	w/s 2A,2B,2C
15	Depreciation Expense	(B)	9,054,319	2,110,342	1,145,314	12,309,975	w/s 4ABC line 3
16	Amortization of Loss on Reacquired Debt	(C)	68,135	41,105	3,219	112,459	w/s 4ABC line 4
17	Investment Tax Credit	(D)	(108,845)	(3,121)	(19,867)	(131,833)	w/s 4ABC line 5
18	Property Tax Expense	(E)	3,962,211	1,709,592	1,003,673	6,675,476	w/s 4ABC line 8
19	Payroll Tax Expense	(F)	81,627	33,450	28,270	143,347	w/s 4ABC line 19
20	Operation & Maintenance Expense	(G)	5,227,338	2,721,410	1,665,137	9,613,885	w/s 4ABC line 17
21	Administrative & General Expense	(H)	6,526,023	1,929,058	1,601,005	10,056,086	w/s 4ABC line 18
22	Transmission Related Integrated Facilities Charge	(I)	-	-	-	-	
23	Transmission Support Revenue	(J)	(1,473,441)	(361,118)	-	(1,834,559)	w/s 7
24	Transmission Support Expense	(K)	1,861,473	1,078,657	390,766	3,330,896	w/s 7
25	Transmission Related Expense from Generators	(L)	-	-	-	-	
26	Transmission Related Taxes and Fees Charge	(M)	2,408,827	(14,309)	(29,103)	2,365,416	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(208,117)	(52,691)	(38,593)	(299,401)	
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)		65,836,461	16,277,309	11,395,264	93,509,035	

Worksheet 1B

Northeast Utilities System Companies'
Annual Revenue Requirements of PTF Facilities
for costs in 2009
for Rates billed June 1, 2010 - May 31, 2011
Post - 1996

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	CL&P	PSNH	WMECO	Total	Reference
1	Transmission Plant	(A)(1)(a)	1,853,442,914	283,386,061	90,343,016	2,227,171,991	w/s 3A,3B,3C line 1
2	General Plant	(A)(1)(b)	37,793,190	21,636,393	3,309,273	62,738,856	w/s 3A,3B,3C line 2
3	Plant Held For Future Use	(A)(1)(c)	25,277,216	3,528,234	7,214,155	36,019,605	w/s 3A,3B,3C line 4
4	Total Plant (Lines 1+2+3)		1,916,513,320	308,550,688	100,866,444	2,325,930,452	
5	Accumulated Depreciation	(A)(1)(d)	271,454,022	64,944,070	27,530,720	363,928,812	w/s 3A,3B,3C line 7
6	Accumulated Deferred Income Taxes	(A)(1)(e)	117,486,657	38,926,884	13,284,172	169,697,713	w/s 3A,3B,3C line 10
7	Loss On Reacquired Debt	(A)(1)(f)	4,060,985	1,364,749	48,171	5,473,905	w/s 3A,3B,3C line 11
8	Other Regulatory Assets	(A)(1)(g)	14,394,942	1,847,613	83,734	16,326,289	w/s 3A,3B,3C line 15
9	Net Investment (Line 4-5-6+7+8)		1,546,028,568	207,892,096	60,183,457	1,814,104,121	
10	Prepayments	(A)(1)(h)	4,066,857	5,178,310	2,375,048	11,620,215	w/s 3A,3B,3C line 16
11	Materials & Supplies	(A)(1)(i)	12,163,704	2,271,282	2,793,367	17,228,353	w/s 3A,3B,3C line 17
12	Cash Working Capital	(A)(1)(j)	7,021,042	1,702,771	561,995	9,285,808	w/s 3A,3B,3C line 24
13	Total Investment Base (Line 9+10+11+12)		1,569,280,171	217,044,459	65,913,867	1,852,238,497	

	II. REVENUE REQUIREMENTS		CL&P	PSNH	WMECO	Total	Reference
14	Investment Return and Income Taxes	(A)	203,433,164	25,324,292	8,238,238	236,995,694	w/s 2A,2B,2C
15	Depreciation Expense	(B)	43,269,835	6,181,623	1,576,566	51,028,024	w/s 4ABC line 3
16	Amortization of Loss on Reacquired Debt	(C)	325,610	120,406	4,431	450,447	w/s 4ABC line 4
17	Investment Tax Credit	(D)	(520,163)	(9,141)	(27,348)	(556,652)	w/s 4ABC line 5
18	Property Tax Expense	(E)	18,935,073	5,007,744	1,381,592	25,324,409	w/s 4ABC line 8
19	Payroll Tax Expense	(F)	390,088	97,982	38,914	526,984	w/s 4ABC line 19
20	Operation & Maintenance Expense	(G)	24,981,012	7,971,563	2,292,122	35,244,697	w/s 4ABC line 17
21	Administrative & General Expense	(H)	31,187,320	5,650,606	2,203,841	39,041,767	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)	11,511,585	(41,913)	(40,061)	11,429,611	
25	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(994,870)	(154,346)	(53,120)	(1,202,336)	
26	Total Revenue Requirements (Line 14 thru 25)		332,518,654	50,148,816	15,615,175	398,282,645	

Northeast Utilities System Companies'
Annual Revenue Requirements of post-2003 PTF Incremental Return
for costs in 2009
for Rates billed June 1, 2010 - May 31, 2011

Line	I. INVESTMENT BASE	CL&P	PSNH	WMECO	Total	Reference
1	Transmission Plant	$ 1,594,157,157	$ 126,576,637	$ 12,308,623	$ 1,733,042,417	
2	Accumulated Depreciation	$ 66,660,409	$ 7,294,255	$ 1,066,502	$ 75,021,166	
3	Accumulated Deferred Income Taxes	$ 56,758,401	$ 8,958,048	$ 1,371,696	$ 67,088,145	
4	Net Investment (Line 1-2-3)	$ 1,470,738,347	$ 110,324,334	$ 9,870,425	$ 1,590,933,106	
	II. INCREMENTAL RETURN					
5	Incremental Revenue Requirements	$ 12,084,027	$ 871,838	$ 81,205	$ 13,037,070	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, 2010 - May 31, 2011

Line	I. INVESTMENT BASE	CL&P	Reference
1	Transmission Plant	$ 412,093,832	
2	Accumulated Depreciation	$ 8,396,701	
3	Accumulated Deferred Income Taxes	$ 8,217,439	
4	Net Investment (Line 1-2-3)	$ 395,479,692	
	II. INCREMENTAL RETURN		
5	Incremental Revenue Requirements	$ 1,525,247	w/s 2A M-N Adv Tech

Northeast Utilities System Companies'
Forecasted Transmission Revenue Requirements of PTF Facilities
Year 2010 Estimates
Post-1996

Line No.	I. FORECASTED TRANSMISSION REVENUE REQUIREMENTS	Attachment F Reference	CL&P	PSNH	WMECO	Total NU	Reference
1	Total Forecasted Plant Additions (excl. Localized)	App. C	69,597,000	29,051,000	35,736,000	134,384,000	
2	Carrying Charge Factor (line 14)	App. C	17.37%	17.77%	17.39%		
3	Total Forecasted Revenue Requirements (Lines 1 * 2)		$ 12,089,000	$ 5,162,000	$ 6,214,000	$ 23,465,000	
	II. CARRYING CHARGE FACTOR (Post 96) (*)						
4	Investment Return and Income Taxes	(A)	$ 203,433,164	25,324,292	8,238,238	236,995,694	w/s 1B line 14
5	Depreciation Expense	(B)	43,269,835	6,181,623	1,576,566	51,028,024	w/s 1B line 15
6	Amortization of Loss on Reacquired Debt	(C)	325,610	120,406	4,431	450,447	w/s 1B line 16
7	Investment Tax Credit	(D)	(520,163)	(9,141)	(27,348)	(556,652)	w/s 1B line 17
8	Property Tax Expense	(E)	18,935,073	5,007,744	1,381,592	25,324,409	w/s 1B line 18
9	Payroll Tax Expense	(F)	390,088	97,982	38,914	526,984	w/s 1B line 19
10	Operation & Maintenance Expense	(G)	24,981,012	7,971,563	2,292,122	35,244,697	w/s 1B line 20
11	Administrative & General Expense	(H)	31,187,320	5,650,606	2,203,841	39,041,767	w/s 1B line 21
12	Total Expenses (Lines 4 thru 11)		$322,001,939	$50,345,075	$15,708,356	$388,055,370	
13	PTF Transmission Plant		$1,853,442,914	$283,386,061	$90,343,016	$2,227,171,991	w/s 1B line 1
14	Carrying Charge Factor (Lines 12/13)		17.37%	17.77%	17.39%	17.42%	

(*) The Carrying Charge Factor shall reflect the most recent calendar year data used in determining Post-1996 Annual Transmission Revenue Requirements and shall equal the sum of Attachment F Sections II.A through II. H divided by PTF Transmission Plant.

NU Transmission 2010 PTF In-Service Forecast

($ X 1000)

COMPANY	ISO-NE RSP Project ID	Project Title	Estimated PTF In-Service
CL&P	222 (a)	Middletown - Norwalk 345-kV project	12,898
CL&P	248 (a)	Glenbrook Cables 115-kV project	(560)
CL&P	(b)	Easements & land acquisitions for planned projects	600
CL&P	582	345-kV 310/368 line separation project	10,538
CL&P	(b)	NEEWS Projects	5,007
CL&P	211	Rood Ave 115-kV substation project	131
CL&P	809	Bunker Hill 115-kV substation upgrades	466
CL&P	1055	Waterside 115-kV substation upgrades	430
CL&P	N/A	Relay replacements	4,494
CL&P	N/A	SCADA upgrades	6,877
CL&P	N/A	Critical infrastructure protection	590
CL&P	N/A	Substation disconnect switch replacements	2,016
CL&P	N/A	Digital fault recorder (DFR) installations	812
CL&P	(c)	Mystic 115-kV substation upgrades	783
CL&P	N/A	Norwalk Substation modifications	1,430
CL&P	N/A	Other projects	23,085
		Total CL&P	**69,597**
WMECO	(b)	Easements & land acquisitions for planned projects	6,000
WMECO	1000	Agawam - West Springfield 1311/1412 115-kV project	1,120
WMECO	N/A	Relay replacements	3,608
WMECO	N/A	Critical infrastructure protection	92
WMECO	N/A	SCADA upgrades	2,129
WMECO	N/A	Breckwood cables 115-kV project	922
WMECO	N/A	Structure replacements	17,667
WMECO	N/A	Other projects	4,198
		Total WMECO	**35,736**
PSNH	277, 1137-1141	Deerfield projects	2,291
PSNH	176 - 180	Monadnock projects	70
PSNH	282	New Weare 115-kV substation	9
PSNH	1143	Littleton 115-kV substation project	5,456
PSNH	FUT (c)	Easements & land acquisitions for planned projects	1,299
PSNH	FUT (c)	Manchester area projects	1,480
PSNH	N/A	Relay replacements	6,788
PSNH	N/A	Digital fault recorder (DFR) installations	182
PSNH	N/A	Critical infrastructure protection	194
PSNH	N/A	Other projects	11,282
		Total PSNH	**29,051**

Total Northeast Utilities 134,384

(a) There are multiple RSP numbers associated with the project
(b) There are multiple RSP numbers assciated with the NEEWS projects in both CT and MA
(c) Presently part of NU LSP

Note:
"FUT" = Future - Not Yet Filed

Northeast Utilities System Companies'
Transmission Revenue Requirements of PTF Facilities
Year 2009 True-up
Pre-97 and Post-1996

Line	**I.** ANNUAL TRUE-UP		**PRE-97**	**WP**	**POST-96**	**WP**	**TOTAL**	
1	Transmission Revenue Requirements (as billed)	Section C	89,372,178	**B**	405,291,847	**B**	494,664,025	ATRR - Prior Year
2	True-up 2009 Actual Annual RR @ 11.64% ROE		93,509,034	**B**	412,844,962	**B**	506,353,996	PTF Pre and Post on ATRR
3	Total Rate Year Surcharge/(Refund) (Line 2 - 1)		4,136,856		7,553,115		11,689,971	

This true-up amount will be given to ISO-NE which will develop a rate based on what should have been billed versus what was actually billed in order to rebill the difference to customers.

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

	Surcharge / (Refund)
Pre	4,136,856
Post	7,553,115

Initial Billing Period	Balance Pre 97	Balance Post 96	FERC Monthly Interest Rate	Interest Pre 97	Interest Post 96
June 2009	$ 4,136,856	$ 7,553,115	0.28%	$ 11,584	$ 21,148
July 2009	$ 4,148,440	$ 7,574,263	0.28%	$ 11,615	$ 21,208
August 2009	$ 4,148,440	$ 7,574,263	0.28%	$ 11,615	$ 21,208
September 2009	$ 4,148,440	$ 7,574,263	0.27%	$ 11,201	$ 20,450
October 2009	$ 4,182,871	$ 7,637,129	0.28%	$ 11,712	$ 21,384
November 2009	$ 4,182,871	$ 7,637,129	0.27%	$ 11,293	$ 20,620
December 2009	$ 4,182,871	$ 7,637,129	0.28%	$ 11,712	$ 21,384
January 2010	$ 4,217,588	$ 7,700,517	0.28%	$ 11,809	$ 21,561
February 2010	$ 4,217,588	$ 7,700,517	0.25%	$ 10,544	$ 19,251
March 2010	$ 4,217,588	$ 7,700,517	0.28%	$ 11,809	$ 21,561
April 2010	$ 4,251,750	$ 7,762,890	0.27%	$ 11,479	$ 20,960
May 2010	$ 4,251,750	$ 7,762,890	0.28%	$ 11,905	$ 21,736
Total Surcharge/(Refund)				**$ 4,275,134**	**$ 7,805,586**

	Interest	Principal	Total (check)	variance
Pre 97	$ 138,278	$ 4,136,856	$ 4,275,134	$ -
Post 96	$ 252,471	$ 7,553,115	$ 7,805,586	$ -

Note: Minor immaterial variance due to rounding

2009 AFUDC Equity Amortization in Depreciation
Excluding Estimated Middletown - Norwalk Localized Cost
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

"C" component of the Federal & State Income Tax Formula

2009 AFUDC Equity Amortization in Depreciation
Excluding Estimated Middletown - Norwalk Localized Cost
POST-96

	a	b	c	d	e	f	g
	Transmission	PTF Allocator	Transmission PTF level (a*b)	General General Transmission	PTF Allocator	PTF level (d*e)	Total at PTF level (c+f)
CL&P	3,144,044	74.9358%	2,356,015	46,096	74.9358%	34,542	2,390,557
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		2,480,909	55,323		40,827	2,521,736

"C" component of the Federal & State Income Tax Formula

Northeast Utilities Systems Companies
Capitalization
Calendar Year 2009- Year End

Line No.	Long Term Debt	CL&P Year End	PSNH Year End	WMECO Year End	Reference
1	Outstanding Bonds	2,341,017,150	837,285,000	248,832,680	FF1 page 257 ln 33 + page 257, line 33 footnote - PCRB Debt Balance
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)	0	-	-	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	0	-	-	FF1 page 117 ln. 66
10	Annual Interest Cost	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	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	

Connecticut Light & Power Company (CL&P)
Investment Return and Income Taxes
for costs in 2009
Pre 97

for Rates billed June 1, 2010 - May 31, 2011

		12/31/2009 CAPITALIZATION	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 +((108,845) + 500,230) / 328,424,615) x 0.35) / (1 - 0.35)

= 0.0322494

(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 +((108,845) + 500,230) / 328,424,615) + 0.0322494)* 0.0825 / (1 - 0.0825)

= 0.0082852

(a)+(b)+(c) Cost of Capital Rate = 0.1296346

		Pre-1997 PTF	
INVESTMENT BASE	$	328,424,615	From Worksheet 1, line 13
x Cost of Capital Rate		0.1296346	
= Investment Return and Income Taxes	$	42,575,194	To Worksheet 1, line 14

Connecticut Light & Power Company (CL&P)
Investment Return and Income Taxes
for costs in 2009
POST-96
for Rates billed June 1, 2010 - May 31, 2011

		12/31/2009 CAPITALIZATION	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 +((520,163) + 2,390,557) / 1,569,280,171) x 0.35) / (1 - 0.35)

= 0.0322495

(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 +((520,163) + 2,390,557) / 1,569,280,171) + 0.0322495)* 0.0825 / (1 - 0.0825)

= 0.0082852

(a)+(b)+(c) Cost of Capital Rate = 0.1296347

		Post - 1996 PTF	
INVESTMENT BASE	$	1,569,280,171	From Worksheet 1, line 13
x Cost of Capital Rate		0.1296347	
= Investment Return and Income Taxes	$	203,433,164	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 12/31/2009	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

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

$$= \frac{0.0049 + ((0 + 0) / 1{,}470{,}738{,}347) \times 0.35)}{(1 - 0.35)}$$

= 0.0026385

(c) State Income Tax

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

$$= \frac{0.0049 + ((0 + 0) / 1{,}470{,}738{,}347) + 0.0026385)^* 0.0825}{(1 - 0.0825)}$$

= 0.0006778

(a)+(b)+(c) Cost of Capital Rate = 0.0082163

	(post-2003 PTF)	
INVESTMENT BASE	$ 1,470,738,347	From Worksheet 1 Line 4
x Cost of Capital Rate	0.0082163	
= Investment Return and Income Taxes	12,084,027	To Worksheet 1a Line 5

Connecticut Light & Power Company (CL&P)
Investment Return and Income Taxes
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 = (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)

= (0.0023 + ((0 + 0) / 395,479,692) x 0.35) / (1 - 0.35)

= 0.0012385

(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)

= (0.0023 + ((0 + 0) / 395,479,692) + 0.0012385)* 0.0825 / (1 - 0.0825)

= 0.0003182

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

	(post-2003 PTF)		
INVESTMENT BASE	$ 395,479,692	From Worksheet 1 Line 4	
x Cost of Capital Rate	0.0038567		
= Investment Return and Income Taxes	$ 1,525,247	To Worksheet 1a Line 5	CL&P - 2A -Adv tech

Connecticut Light & Power Company (CL&P)
Rate Base Items
Calendar Year 2009

Line No.		(1) Total Factors	(2) Wage/Plant Allocation (a)	(3) = (1)*(2) Transmission Allocated	PRE-97 PTF (4) PTF Allocation Factor (b)	PRE-97 PTF (5) = (3)*(4) PTF Allocated	POST-96 PTF (6) PTF Allocation Factor (b)	POST-96 PTF (7) = (3)*(6) PTF Allocated	Reference
	Transmission Plant								
1	Transmission Plant					387,837,863		1,853,442,914	
2	General Plant	50,434,092		50,434,092	15.6805%	7,908,318	74.9358%	37,793,190	FF1 page 206-207 ln. 96, footnote
3	Total (line 1+2)	50,434,092		50,434,092		395,746,181		1,891,236,104	
4	Transmission Plant Held for Future Use	33,731,829		33,731,829	15.6805%	5,289,319	74.9358%	25,277,216	FF1 page 214 (py ln. 29 & cy ln.14)
	Transmission Accumulated Depreciation								
5	Transmission Accum. Depreciation	354,960,836		354,960,836	15.6805%	55,659,634	74.9358%	265,992,742	FF1 page 219 ln. 25
6	General Plant Accum.Depreciation	7,287,945		7,287,945	15.6805%	1,142,786	74.9358%	5,461,280	FF1 page 219 ln. 28, footnote
7	Total (line 5+6)	362,248,781		362,248,781		56,802,420		271,454,022	
	Transmission Accumulated Deferred Taxes								
8	Accumulated Deferred Taxes (281 to 283)	(196,341,441)		(196,341,441)	15.6805%	(30,787,320)	74.9358%	(147,130,030)	FF1 page 274 ln. 9 & 276 ln. 19 footnote
9	Accumulated Deferred Taxes (190)	39,558,359 (c)		39,558,359	15.6805%	6,202,948	74.9358%	29,643,373	(c)
10	Total (line 8+9)	(156,783,082)		(156,783,082)		(24,584,372)		(117,486,657)	
11	Transmission loss on Reacquired Debt	5,419,285		5,419,285	15.6805%	849,771	74.9358%	4,060,985	FF1 page 110 ln. 81, footnote
	Other Regulatory Assets								
12	FAS 106	-		-	15.6805%	-	74.9358%	-	FF1 page 232
13	FAS 109	22,332,713		22,332,713	15.6805%	3,501,881	74.9358%	16,735,197	FF1 page 232 ln. 10, footnote
14	Other Regulatory Liabilities (254.DK)	(3,123,013)		(3,123,013)	15.6805%	(489,704)	74.9358%	(2,340,255)	FF1 page 278 ln. 5, footnote
15	Total (line 12+13+14)	19,209,700		19,209,700		3,012,177		14,394,942	
16	Transmission Prepayments (165)	5,427,121		5,427,121	15.6805%	851,000	74.9358%	4,066,857	FF1 page 110 ln. 57, footnote
17	Transmission Materials and Supplies	16,232,167		16,232,167	15.6805%	2,545,285	74.9358%	12,163,704	FF1 page 227 ln. 8
18	Cash Working Capital								
19	Operation & Maintenance Expense					5,227,338		24,981,012	w/s 4A, Line 17
20	Administrative & General Expense					6,526,023		31,187,320	w/s 4A, Line 18
21	Transmission Support Expense					388,032		-	w/s 7
22	Subtotal (line 19+20+21)					12,141,393		56,168,332	
23						0.125		0.125	x 45 / 360
24	Total (line 22 * line 23)					1,517,674		7,021,042	

(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	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)
Expense Items
Calendar Year 2009

Line No.		(1) Total Factors	(2) Wage/Plant Allocation (a)	(3) = (1)*(2) Transmission Allocated	PRE-97 PTF (4) PTF Allocation Factor (b)	PRE-97 PTF (5) = (3)*(4) Pre-97 PTF PTF Allocated	POST-96 PTF (6) Allocation Factor (b)	POST-96 PTF (7) = (3)*(6) Post-96 PTF Allocated	Reference
	Depreciation Expense								
1	Transmission Depreciation	56,047,436			15.6805%	8,788,518	74.9358%	41,999,595	FF 1 page 336 ln. 7
2	General Depreciation	1,695,104			15.6805%	265,801	74.9358%	1,270,240	FF1 page 336 ln. 10, footnote
3	Total (line 1+2)	57,742,540				9,054,319		43,269,835	
4	Amortization of Loss on Reacquired Debt	434,518			15.6805%	68,135	74.9358%	325,610	FF1 page 114, ln. 64, footnote
5	Amortization of Investment Tax Credits	694,145			15.6805%	108,845	74.9358%	520,163	FF1 page 266 ln. 8, footnote - difference of PY-CY
	Property Taxes								
6	Transmission Property Taxes	25,268,394			15.6805%	3,962,211	74.9358%	18,935,073	FF1 page 262 ln. 25, footnote
7	General Property Taxes (c)	-		-	15.6805%	-	74.9358%	-	
8	Total (line 6+7)	25,268,394				3,962,211		18,935,073	
	Transmission Operation and Maintenance								
9	Operation and Maintenance	142,969,527		142,969,527	15.6805%	22,418,337	74.9358%	107,135,359	FF1 page 321 ln. 112
10	Transmission of Electricity by Others - #565	95,602,919			15.6805%	14,991,016	74.9358%	71,640,812	FF1 page 321 ln. 96
11	Load Dispatching - #561	-		-	15.6805%	-	74.9358%	-	FF1 page 321 ln. 84
12	Account 561.1	2,919,523			15.6805%	457,796	74.9358%	2,187,768	FF1 page 321 ln. 85
13	Account 561.2	4,969,493			15.6805%	779,241	74.9358%	3,723,929	FF1 page 321 ln. 86
14	Account 561.3	1,684,310			15.6805%	264,108	74.9358%	1,262,151	FF1 page 321 ln. 87
15	Account 561.4	4,456,731			15.6805%	698,838	74.9358%	3,339,687	FF1 page 321 ln. 88
16	**Station Expenses & Rents - #562 / #567	-		-	15.6805%	-	74.9358%	-	
17	O&M less lines 10 thru 16	33,336,551				5,227,338		24,981,012	
	Transmission Administrative and General								
18	Administrative and General	41,618,719			15.6805%	6,526,023	74.9358%	31,187,320	FF1 page 320 ln. 197, footnote
19	*Payroll Tax Expense*	*520,563*		520,563	15.6805%	81,627	74.9358%	390,088	
	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.

Public Service Company of New Hampshire (PSNH)
Investment Return and Income Taxes
for costs in 2009
Pre 97
for Rates billed June 1, 2010 - May 31, 2011

	12/31/2009 CAPITALIZATION	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 828,010,090	53.23%	4.67%	2.49%	
PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	$ 727,445,198	46.77%	11.64%	5.44%	5.44%
TOTAL INVESTMENT RETURN	$ 1,555,455,288	100.00%		7.93%	5.44%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0793

(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)

=(0.0544 +((3,121) + 36,934) / 74,186,255) x 0.35)
(1 - 0.35)

= 0.0295377

(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)

=(0.0544 +((3,121) + 36,934) / 74,186,255) + 0.0295377)* 0.085
(1 - 0.085)

= 0.0078398

(a)+(b)+(c) Cost of Capital Rate = 0.1166775

	Pre-1997 PTF	
INVESTMENT BASE	$ 74,186,255	From Worksheet 1, line 13
x Cost of Capital Rate	0.1166775	
= Investment Return and Income Taxes	$ 8,655,867	To Worksheet 1, line 14

Public Service Company of New Hampshire (PSNH)
Investment Return and Income Taxes
for costs in 2009
Post 96
for Rates billed June 1, 2010 - May 31, 2011

		12/31/2009 CAPITALIZATION	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	828,010,090	53.23%	4.67%	2.49%	
PREFERRED STOCK	$	-	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	$	727,445,198	46.77%	11.64%	5.44%	5.44%
TOTAL INVESTMENT RETURN	$	1,555,455,288	100.00%		7.93%	5.44%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0793

(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)

= (0.0544 +((9,141) + 108,185) / 217,044,459) x 0.35) / (1 - 0.35)

= 0.0295380

(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)

= (0.0544 +((9,141) + 108,185) / 217,044,459) + 0.0295380)* 0.085 / (1 - 0.085)

= 0.0078399

(a)+(b)+(c) Cost of Capital Rate = 0.1166779

		Post - 1996 PTF	
INVESTMENT BASE	$	217,044,459	From Worksheet 1, line 13
x Cost of Capital Rate		0.1166779	
= Investment Return and Income Taxes	$	25,324,292	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 12/31/2009	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 828,010,090	53.23%	#N/A		
PREFERRED STOCK	$ -	0.00%			
COMMON EQUITY	$ 727,445,198	46.77%	1.00%	0.47%	0.47%
TOTAL INVESTMENT RETURN	$ 1,555,455,288	100.00%		0.47%	0.47%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0047

(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)

= (0.0047 + ((0 + 0) / 110,324,334) x 0.35) / (1 - 0.35)

= 0.0025308

(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)

= (0.0047 + ((0 + 0) / 110,324,334) + 0.0025308)* 0.085 / (1 - 0.085)

= 0.0006717

(a)+(b)+(c) Cost of Capital Rate = 0.0079025

	(Post-2003 PTF)	
INVESTMENT BASE	$ 110,324,334	From Worksheet 1 Line 4
x Cost of Capital Rate	0.0079025	
= Investment Return and Income Taxes	$ 871,838	To Worksheet 1a Line 5

Public Service Company of New Hampshire (PSNH)

Worksheet 3B

Rate Base Items
Calendar Year 2009

Line No.		(1) Total Factors	(2) Wage/Plant Allocation (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
	Transmission Plant								
1	Transmission Plant					96,744,902		283,386,061	
2	General Plant	30,902,379		30,902,379	23.9025%	7,386,441	70.0153%	21,636,393	FF1 page 206-207 ln. 96, footnote
3	Total (line 1+2)	30,902,379		30,902,379		104,131,343		305,022,454	
4	Transmission Plant Held for Future Use	5,039,233		5,039,233	23.9025%	1,204,503	70.0153%	3,528,234	FF1 page 214 (py ln. 29 & cy ln.14)
	Transmission Accumulated Depreciation								
5	Transmission Accum. Depreciation	87,695,957		87,695,957	23.9025%	20,961,526	70.0153%	61,400,587	FF1 page 219 ln. 25
6	General Plant Accum.Depreciation	5,061,013		5,061,013	23.9025%	1,209,709	70.0153%	3,543,483	FF1 page 219 ln. 28, footnote
7	Total (line 5+6)	92,756,970		92,756,970		22,171,235		64,944,070	
	Transmission Accumulated Deferred Taxes								
8	Accumulated Deferred Taxes (281-283)	(57,797,485)		(57,797,485)	23.9025%	(13,815,044)	70.0153%	(40,467,083)	FF1 page 274 ln. 9 & 276 ln. 19 footnote
9	Accumulated Deferred Taxes (190)	2,199,803 (c)		2,199,803	23.9025%	525,808	70.0153%	1,540,199	(c)
10	Total (line 8+9)	(55,597,682)		(55,597,682)		(13,289,236)		(38,926,884)	
11	Transmission loss on Reacquired Debt	1,949,216		1,949,216	23.9025%	465,911	70.0153%	1,364,749	FF1 page 110 ln. 81, footnote
	Other Regulatory Assets								
12	FAS 106	-		-	23.9025%	-	70.0153%	-	FF1 page 232
13	FAS 109	2,898,481		2,898,481	23.9025%	692,809	70.0153%	2,029,380	FF1 page 232 ln. 1, footnote
14	Other Regulatory Liabilities (254.DK)	(259,611)		(259,611)	23.9025%	(62,054)	70.0153%	(181,767)	FF1 page 278 ln. 1, footnote
15	Total (line 12+13+14)	2,638,870		2,638,870		630,755		1,847,613	
16	Transmission Prepayments	7,395,969		7,395,969	23.9025%	1,767,821	70.0153%	5,178,310	FF1 page 110 ln. 57, footnote
17	Transmission Materials and Supplies	3,243,979		3,243,979	23.9025%	775,392	70.0153%	2,271,282	FF1 page 227 ln. 8
18	Cash Working Capital								
19	Operation & Maintenance Expense					2,721,410		7,971,563	w/s 4B, Line 17
20	Administrative & General Expense					1,929,058		5,650,606	w/s 4B, Line 18
21	Transmission Support Expense					717,539		-	w/s 7
22	Subtotal (line 19+20+21)					5,368,007		13,622,169	
23						0.125		0.125	x 45 / 360
24	Total (line 22 * line 23)					671,001		1,702,771	

(a) All B/S items functionalized per FERC Form 1; therefore, no need to use Wage/Plant Allocation Factor (column 2

(b) ws 5A & 5B

(c)

Account 190	2,224,310	FF1 page 234 ln. 18, footnote
Less Reserve for Disputed Transactions	24,507	
Total Account 190	2,199,803	

Worksheet 4B

Public Service Company of New Hampshire (PSNH)

Expense Items

Calendar Year 2009

Line No.		(1) Total Factors	(2) Wage/Plant Allocation (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	7,666,136		7,666,136	23.9025%	1,832,398	70.0153%	5,367,468	FF 1 page 336 ln. 7
2	General Depreciation	1,162,824		1,162,824	23.9025%	277,944	70.0153%	814,155	FF1 page 336 ln. 10, footnote
3	Total (line 1+2)	8,828,960		8,828,960		2,110,342		6,181,623	
4	Amortization of Loss on Reacquired Debt	171,971		171,971	23.9025%	41,105	70.0153%	120,406	FF1 page 114, ln. 64, footnote
5	Amortization of Investment Tax Credits	13,056		13,056	23.9025%	3,121	70.0153%	9,141	FF1 page 266 ln. 8, footnote - difference of PY-CY
	Property Taxes								
6	Transmission Property Taxes	7,152,357		7,152,357	23.9025%	1,709,592	70.0153%	5,007,744	FF1 page 262 ln. 24, footnote
7	General Property Taxes (c)	0		0	23.9025%	0	70.0153%	0	
8	Total (line 6+7)	7,152,357		7,152,357		1,709,592		5,007,744	
	Transmission Operation and Maintenance								
9	Operation and Maintenance	49,391,096		49,391,096	23.9025%	11,805,707	70.0153%	34,581,324	FF1 page 321 ln. 112
10	Transmission of Electricity by Others - #565	35,419,092		35,419,092	23.9025%	8,466,048	70.0153%	24,798,784	FF1 page 321 ln. 96
11	Load Dispatching - #561	0		0	23.9025%	0	70.0153%	0	FF1 page 321 ln. 84
12	Account 561.1	601,749		601,749	23.9025%	143,833	70.0153%	421,316	FF1 page 321 ln. 85
13	Account 561.2	496,903		496,903	23.9025%	118,772	70.0153%	347,908	FF1 page 321 ln. 86
14	Account 561.3	1,807		1,807	23.9025%	432	70.0153%	1,265	FF1 page 321 ln. 87
15	Account 561.4	1,486,086		1,486,086	23.9025%	355,212	70.0153%	1,040,488	FF1 page 321 ln. 88
16	**Station Expenses & Rents - #562	0		0	23.9025%	0	70.0153%	0	
17	O&M less lines 10 thru 16	11,385,459		11,385,459		2,721,410		7,971,563	
	Transmission Administrative and General								
18	Administrative and General	8,070,530		8,070,530	23.9025%	1,929,058	70.0153%	5,650,606	FF1 page 320 ln. 197, footnote
19	*Payroll Tax Expense*	139,944		139,944	23.9025%	33,450	70.0153%	97,982	
	Federal Unemployment	1,299							FF1 page 262 ln. 3i, footnote
	FICA	104,911							FF1 page 262 ln. 5i, footnote
	Medicare	28,954							FF1 page 262 ln. 7i, footnote
	CT Unemployment	4,216							FF1 page 262.1 ln. 7i, footnote
	DC Unemployment	4							FF1 page 262 ln. 27i, footnote
	FL Unemployment	0							FF1 page 262.1 ln. 27i, footnote
	GA Unemployment	0							FF1 page 262 & 263 footnote
	MA Unemployment	12							FF1 page 262.1 ln. 15i, footnote
	MA Universal Health	7							FF1 page 262.1 ln. 16i, footnote
	NH Unemployment	532							FF1 page 262 ln. 15i, footnote
	NJ Unemployment	0							FF1 page 262 & 263 footnote
	NY Unemployment	9							FF1 page 262.1 ln. 22i, footnote
	Total	139,944	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.

Western Massachusetts Electric Company (WMECO)
Investment Return and Income Taxes
Pre 97
for Rates billed June 1, 2010 - May 31, 2011

		12/31/2009 CAPITALIZATION	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	246,358,108	49.95%	5.82%	2.91%	
PREFERRED STOCK	$	-	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	$	246,807,728	50.05%	11.64%	5.83%	5.83%
TOTAL INVESTMENT RETURN	$	493,165,836	100.00%		8.74%	5.83%

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)

= (0.0583 +((19,867) + 16,704) / 47,932,704) x 0.35) / (1 - 0.35)

= 0.0313568

(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)

= (0.0583 +((19,867) + 16,704) / 47,932,704) + 0.0313568)* 0.065 / (1 - 0.065)

= 0.0062282

(a)+(b)+(c) Cost of Capital Rate = 0.1249850

		Pre-1997 PTF	
INVESTMENT BASE	$	47,932,704	From Worksheet 1, line 13
x Cost of Capital Rate		0.1249850	
= Investment Return and Income Taxes	$	5,990,869	To Worksheet 1, line 14

Western Massachusetts Electric Company (WMECO)
Investment Return and Income Taxes
Post 96
for Rates billed June 1, 2010 - May 31, 2011

	12/31/2009 CAPITALIZATION	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 246,358,108	49.95%	5.82%	2.91%	
PREFERRED STOCK	$ -	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	$ 246,807,728	50.05%	11.64%	5.83%	5.83%
TOTAL INVESTMENT RETURN	$ 493,165,836	100.00%		8.74%	5.83%

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)

= (0.0583 +((27,348) + 22,994) / 65,913,867) x 0.35) / (1 - 0.35)

= 0.0313567

(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)

= (0.0583 +((27,348) + 22,994) / 65,913,867) + 0.0313567)* 0.065 / (1 - 0.065)

= 0.0062282

(a)+(b)+(c) Cost of Capital Rate = 0.1249849

	Post - 1996 PTF	
INVESTMENT BASE	$ 65,913,867	From Worksheet 1, line 13
x Cost of Capital Rate	0.1249849	
= Investment Return and Income Taxes	$ 8,238,238	To Worksheet 1, line 14

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

	CAPITALIZATION 12/31/2009	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 246,358,108	49.95%	#N/A		
PREFERRED STOCK	$ -	0.00%			
COMMON EQUITY	$ 246,807,728	50.05%	1.00%	0.50%	0.50%
TOTAL INVESTMENT RETURN	$ 493,165,836	100.00%		0.50%	0.50%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0050

(b) Federal Income Tax

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

$$= \frac{\left(0.0050 + \left(\left(0 + 0 \right) / 9{,}870{,}425 \right) \times 0.35 \right)}{\left(1 - 0.35 \right)}$$

$$= 0.0026923$$

(c) State Income Tax

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

$$= \frac{\left(0.0050 + \left(\left(0 + 0 \right) / 9{,}870{,}425 \right) + 0.0026923 \right) * 0.065}{\left(1 - 0.065 \right)}$$

$$= 0.0005348$$

(a)+(b)+(c) Cost of Capital Rate = 0.0082271

	(Post-2003 PTF)	
INVESTMENT BASE	$ 9,870,425	From Worksheet 1 Line 4
x Cost of Capital Rate	0.0082271	
= Investment Return and Income Taxes	$ 81,205	To Worksheet 1a Line 5

Western Massachusetts Electric Company
Rate Base Items
Calendar Year 2009

Line No.		(1) Total Factors	(2) Wage/Plant Allocation (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
	Transmission Plant								
1	Transmission Plant					65,630,687		90,343,016	
2	General Plant	6,342,726		6,342,726	37.9026%	2,404,058	52.1743%	3,309,273	FF1 page 206-207 ln. 96, footnote
3	Total (line 1+2)	6,342,726		6,342,726		68,034,745		93,652,289	
4	Transmission Plant Held for Future Use	13,827,027		13,827,027	37.9026%	5,240,803	52.1743%	7,214,155	FF1 page 214 ln. 34
	Transmission Accumulated Depreciation								
5	Transmission Accum. Depreciation	51,548,236		51,548,236	37.9026%	19,538,122	52.1743%	26,894,931	FF1 page 219 ln. 25
6	General Plant Accum.Depreciation	1,218,587		1,218,587	37.9026%	461,876	52.1743%	635,789	FF1 page 219 ln. 28, footnote
7	Total (line 5+6)	52,766,823		52,766,823		19,999,998		27,530,720	
	Transmission Accumulated Deferred Taxes								
8	Accumulated Deferred Taxes (281-283)	(23,945,188)		(23,945,188)	37.9026%	(9,075,849)	52.1743%	(12,493,234)	FF1 page 274 ln. 9 & 276 ln. 19 footnote
9	Accumulated Deferred Taxes (190)	(1,515,953) (c)		(1,515,953)	37.9026%	(574,586)	52.1743%	(790,938)	(c)
10	Total (line 8+9)	(25,461,141)		(25,461,141)		(9,650,435)		(13,284,172)	
11	Transmission loss on Reacquired Debt	92,327		92,327	37.9026%	34,994	52.1743%	48,171	FF1 page 110 ln. 81, footnote
	Other Regulatory Assets								
12	FAS 106	0		0	37.9026%	0	52.1743%	0	FF1 page 232
13	FAS 109	412,419		412,419	37.9026%	156,318	52.1743%	215,177	FF1 page 232 ln. 10, footnote
14	Other Regulatory Liabilities (254.DK)	(251,931)		(251,931)	37.9026%	(95,488)	52.1743%	(131,443)	FF1 page 278 ln. 5, footnote
15	Total (line 12+13+14)	160,488		160,488		60,830		83,734	
16	Transmission Prepayments	4,552,142		4,552,142	37.9026%	1,725,380	52.1743%	2,375,048	FF1 page 110 ln. 57, footnote
17	Transmission Materials and Supplies	5,353,913		5,353,913	37.9026%	2,029,272	52.1743%	2,793,367	FF1 page 227 ln. 8
18	Cash Working Capital								
19	Operation & Maintenance Expense					1,665,137		2,292,122	w/s 4C, Line 17
20	Administrative & General Expense					1,601,005		2,203,841	w/s 4C, Line 18
21	Transmission Support Expense					390,766			w/s 7
22	Subtotal (line 19+20+21)					3,656,908		4,495,963	
23						0.125		0.125	x 45 / 360
24	Total (line 22 * line 23)					457,113		561,995	

(a) All B/S items functionalized per FERC Form 1; therefore, no need to use Wage/Plant Allocation Factor (column 2)
(b) ws 5A & 5B

(c)			
	Account 190	(1,515,953)	FF1 page 234 ln. 18, footnote
	Less Reserve for Disputed Transactions	0	
	Total Account 190	(1,515,953)	

Worksheet 4C

Western Massachusetts Electric Company
Expense Items
Calendar Year 2009

Line No.		(1) Total Factors	(2) Wage/Plant Allocation (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	2,844,671		2,844,671	37.9026%	1,078,204	52.1743%	1,484,187	FF 1 page 336 ln. 7
2	General Depreciation	177,059		177,059	37.9026%	67,110	52.1743%	92,379	FF1 page 336 ln. 10, footnote
3	Total (line 1+2)	3,021,730		3,021,730		1,145,314		1,576,566	
4	Amortization of Loss on Reacquired Debt	8,492		8,492	37.9026%	3,219	52.1743%	4,431	FF1 page 114, ln. 64, footnote
5	Amortization of Investment Tax Credits	52,416		52,416	37.9026%	19,867	52.1743%	27,348	FF1 page 266 ln. 8, footnote - difference of PY-CY
	Property Taxes								
6	Transmission Property Taxes	2,648,032		2,648,032	37.9026%	1,003,673	52.1743%	1,381,592	FF1 page 262 ln. 33i, footnote
7	General Property Taxes (c)			-	37.9026%	-	52.1743%	-	
8	Total (line 6+7)	2,648,032		2,648,032		1,003,673		1,381,592	
	Transmission Operation and Maintenance								
9	Operation and Maintenance	26,095,911		26,095,911	37.9026%	9,891,029	52.1743%	13,615,359	FF1 page 321 ln. 112
10	Transmission of Electricity by Others - #565	20,948,437		20,948,437	37.9026%	7,940,002	52.1743%	10,929,700	FF1 page 321 ln. 96
11	Load Dispatching - #561	-		-	37.9026%	-	52.1743%	-	FF1 page 321 ln. 84
12	Account 561.1	1,005		1,005	37.9026%	381	52.1743%	524	FF1 page 321 ln. 85
13	Account 561.2	45,252		45,252	37.9026%	17,152	52.1743%	23,610	FF1 page 321 ln. 86
14	Account 561.3	1,005		1,005	37.9026%	381	52.1743%	524	FF1 page 321 ln. 87
15	Account 561.4	707,013		707,013	37.9026%	267,976	52.1743%	368,879	FF1 page 321 ln. 88
16	**Station Expenses & Rents - #562 / #567	-		-	37.9026%	-	52.1743%	-	
17	O&M less lines 10 thru 16	4,393,199		4,393,199		1,665,137		2,292,122	
	Transmission Administrative and General								
18	Administrative and General	4,223,997		4,223,997	37.9026%	1,601,005	52.1743%	2,203,841	FF1 page 320 ln. 197, footnote
19	*Payroll Tax Expense*	74,585		74,585	37.9026%	28,270	52.1743%	38,914	
	Federal Unemployment	678							FF1 page 262 ln. 3i, footnote
	FICA	54,338							FF1 page 262 ln. 5i, footnote
	Medicare	15,641							FF1 page 262 ln. 9i, footnote
	CT Unemployment	2,812							FF1 page 262 ln. 13i, footnote
	DC Unemployment	3							FF1 page 262.1 ln. 8i, footnote
	FL Unemployment	-							FF1 page 262.1 ln. 13i, footnote
	GA Unemployment	-							FF1 page 262 & 263 footnote
	MA Unemployment	701							FF1 page 262 ln. 16i, footnote
	MA Universal Health	223							FF1 page 262 ln. 28i, footnote
	NH Unemployment	183							FF1 page 262 ln. 38i, footnote
	NJ Unemployment	-							FF1 page 262 & 263 footnote
	NY Unemployment	6							
	Total	74,585	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

Northeast Utilities System Companies
Allocation Factors
Calendar Year 2009
PRE-1997

Line No.	PTF Transmission Plant Allocation Factor	CL&P	PSNH	WMECO	TOTAL	Reference
1	PTF Transmission Investment	387,837,863	96,744,902	65,630,687	550,213,452	
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,3B,3C 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%	

Northeast Utilities System Companies
Allocation Factors
Calendar Year 2009
POST - 1996

Line No.	PTF Transmission Plant Allocation Factor	CL&P	PSNH	WMECO	TOTAL	Reference
1	PTF Transmission Investment	1,853,442,914	283,386,061	90,343,016	2,227,171,991	
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)	74.9358%	70.0153%	52.1743%	72.9914%	
	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,3B,3C 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%	

Northeast Utilities System Companies
Affiliated Company Wages and Salaries
PRE and POST

Line		CL&P	PSNH	WMECO
"Affiliated" Transmission Wages and Salaries				
#560 - 573				
1	560	3,770,513	545,978	222,905
2	561	5,372,878	69,810	40,262
3	562	194,157	47,460	9,710
4	563	1,642	0	0
5	564	1,656	322	130
6	565	0	0	0
7	566	0	199	0
8	567	0	0	0
9	568	1,382,636	224,313	90,332
10	569	844,055	160,022	65,950
11	570	874,102	142,486	40,974
12	571	137,070	2,992	2,098
13	572	85,378	0	0
14	573	146,396	7,319	2,502
15 = 1 thru 14	Total Transmission	12,810,483	1,200,901	474,863
16 = Total "Affiliated" Wages and Salaries		90,628,945	20,459,124	12,854,932
Less "Affiliated" Administrative and General Salaries				
#920 - 935				
17	920	11,696,597	2,089,974	1,055,647
18	921	67,926	3,547	1,577
19	923	3,429	635	196
20	924	0	0	0
21	925	46,983	7,649	2,295
22	926	0	0	0
23	927	0	0	0
24	928	217,957	55,585	71,022
25	929	0	0	0
26	930	9,607	2,689	1,017
27	931	0	0	0
28	935	55,512	9,036	10,126
29 = 17 thru 28		12,098,011	2,169,115	1,141,880
30 = 16 less 29	Total "Affiliated" less A&G	78,530,934	18,290,009	11,713,052

Northeast Utilities Systems Companies
Transmission Support Revenues and Expenses
Calendar Year 2009
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.

Participant	PTF Supporting Facilities	FERC Form 1	CL&P Revenues (a)	CL&P Expenses (b)	PSNH Revenues (a)	PSNH Expenses (b)	WMECO Revenues (a)	WMECO Expenses (b)	TOTAL Revenues (a)	TOTAL 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, 9		96,043		51,015		20,162		167,220
	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**			-		4,594		-		4,594
	115 kV Wyman 164-167 lines			-		11,265		-		11,265
	115 kV Saco Valley	FF1 page 332 ln 13		-		60,729		-		60,729
										-
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, 15		521,370		276,933		109,447		907,750
	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									-
	Granite Ridge	FF1 page 332.2 ln 6		-		0		-		-
	Moore 115 kV Substation	FF1 Page 332 ln. 4		-		13,319		-		13,319
	HQ Phase II - AC in MA	FF1 page 332 ln. 6, 8		1,244,060		660,802		261,157		2,166,019
	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	-		361,118		-		361,118	-
	Fairmont 115 kV Substation	FF1 page 330	-		-		-		0	-
	345 kV Millstone-Manchester 310 line	FF1 page 330.1 ln. 7	1,218,361		-		-		1,218,361	-
	UI Substations	FF1 page 330	-		-		-		0	-
	Black Pond	FF1 page 330.1 ln 8	255,080		-		-		255,080	-
		Total =	1,473,441	1,861,473	361,118	1,078,657	0	390,766	1,834,559	3,330,896
	Amount by which Support Expense exceeds Support Revenues (To Worksheet 3, Line 21, Column 5)			388,032		717,539		390,766		1,496,337

Connecticut Light and Power Company

Worksheet 8

Substations and Lines

PTF Investment as of 12/31/09 (101 + 106)

	350	352	353	354	355	356	357	358	359	361	362	Grand Total
1975 + PRIOR	23,083,148.55	1,766,902.63	35,443,580.04	15,972,773.56	32,513,601.38	31,083,641.64	817,910.81	5,085,041.03	0.00	2,526,094.30	11,682,763.46	159,975,457.40
1976	48,807.91	0.00	2,370,714.51	2,012,609.78	4,276,799.48	3,119,168.58	0.00	0.00	341,207.64	178,912.70	788,582.84	13,136,803.43
1977	2,373,502.57	224,328.89	3,340,486.57	0.00	2,193,810.17	1,508,170.64	0.00	363,428.49	0.00	374,767.11	389,941.75	10,768,436.20
1978	4,634,663.83	423,683.97	3,937,441.96	124,018.10	5,791,654.09	5,014,254.09	0.00	0.00	0.00	70,879.20	335,341.12	20,331,936.36
1979	5,578,467.48	0.00	639,822.76	0.00	3,011,212.50	1,408,337.37	0.00	0.00	53,118.62	43,086.38	482,287.29	11,216,332.40
1980	303,334.35	0.00	927,105.37	1,207,553.88	1,165,524.66	1,783,085.97	0.00	0.00	0.00	27,990.02	156,789.90	5,571,384.15
1981	807,549.40	423,734.90	6,795,372.86	3,363,183.07	3,778,233.85	2,871,087.62	0.00	0.00	445,359.14	168,536.65	223,708.06	18,876,765.56
1982	1,319,460.35	10,210.30	821,677.15	0.00	4,342,413.66	3,137,589.63	0.00	0.00	457,303.27	118,250.32	191,495.79	10,398,400.46
1983	143,100.70	97,133.02	2,281,807.84	1,633,362.93	1,373,080.64	943,747.96	0.00	452,348.46	114,420.29	75,953.86	197,940.00	7,312,895.70
1984	23,940.59	127,646.92	2,218,412.63	736,432.67	22,280.71	699,160.65	0.00	0.00	105,693.03	17,114.80	164,650.31	4,115,332.31
1985	0.00	660,599.28	8,360,343.50	254,460.70	12,716,402.36	11,134,043.31	0.00	18,998.68	2,086,693.18	102,726.89	198,231.27	35,532,499.17
1986	17.45	14,867.71	4,530,057.21	0.00	203,272.05	608,619.41	0.00	0.00	7,934.56	59,784.99	194,795.85	5,619,349.23
1987	26,687.13	5,818.37	673,510.40	220,544.60	2,286,006.98	1,241,334.23	0.00	0.00	141,730.14	13,287.97	238,579.75	4,847,499.56
1988	12,321.82	95,941.90	2,828,463.48	0.00	419,496.90	813,077.54	0.00	0.00	247,458.25	165,929.84	489,472.88	5,072,162.61
1989	13,407.54	201,432.72	767,180.24	180,966.57	2,241,153.50	1,822,558.41	0.00	23,806.86	552,449.96	49,462.71	504,148.78	6,356,567.30
1990	15,660.14	175,832.80	7,401,189.09	428,506.43	580,138.86	814,674.48	0.00	0.00	96,769.87	1,486,279.29	2,343,288.83	13,342,339.78
1991	893,384.98	8,638.88	7,884,411.75	92,885.29	6,010,808.09	5,983,734.62	0.00	0.00	1,288,940.98	40,296.17	632,675.53	22,835,776.28
1992	42,485.41	10,038.23	2,239,251.72	0.00	2,634,509.38	1,559,020.21	0.00	0.00	744,782.51	0.00	343,319.62	7,573,407.08
1993	1,193.02	0.00	887,003.55	140,492.94	14,639,277.63	2,889,659.96	0.00	0.00	19,686.26	0.00	59,823.55	18,637,136.91
1994	(15,032.07)	0.00	2,817,065.99	0.00	390,839.13	192,107.76	0.00	0.00	90,525.06	56,348.54	68,489.61	3,600,344.02
1995	2,545.44	36,807.38	204,925.73	0.00	347,481.69	256,664.17	0.00	0.00	0.00	1,642.92	2,828.13	852,895.46
1996	0.00	93,274.62	1,338,881.11	0.00	324,259.63	72,341.50	0.00	0.00	0.00	28,145.94	7,239.31	1,864,142.12
Pre-1997	39,308,646.58	4,376,892.51	98,708,705.46	26,367,790.52	101,262,257.34	78,956,079.75	817,910.81	5,943,623.52	6,794,072.76	5,605,490.61	19,696,393.62	387,837,863.49
1997	39,442.79	38,745.58	4,938,525.32	112,607.52	118,897.46	4,837,106.76	0.00	0.00	0.00	15,508.21	78,466.29	10,179,299.93
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	584,386.76	28,802.26	26,718.64	6,688.86	0.00	0.00	0.00	10,683.89	32,726.56	690,006.97
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	17,387,594.02	0.00	1,274,515.96	28,447.99	0.00	0.00	0.00	0.00	23,240.49	19,342,132.21
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)	192,434.36	13,929,527.99	55,332.28	8,981,550.27	2,570,587.65	0.00	0.00	0.00	43,329.91	93,528.19	25,835,413.55
2004	607,255.01	1,996,237.25	56,090,363.28	0.00	2,261,294.57	377,603.79	1,058,908.61	1,180,509.94	18,824.61	7,636.45	340,694.08	63,939,327.58
2005	2,790,727.81	4,562,774.63	77,071,830.68	0.00	3,492,551.70	3,110,943.64	16,291,589.29	9,150,257.10	0.00	163,514.63	127,926.95	116,762,116.43
2006	11,211,462.88	7,283,645.70	79,400,732.11	0.00	20,113,526.25	9,020,162.39	20,432,422.46	67,443,769.08	3,968,765.88	1,013,094.25	896,701.29	220,784,282.31
2007	10,865,658.73	3,591,028.84	78,158,261.68	0.00	85,019,015.71	46,211,315.98	0.00	0.00	29,274.47	19,465.06	141,854.77	224,035,875.24
2008	1,318,453.62	8,425,563.42	210,910,922.50	384,927.18	115,436,538.00	59,727,193.73	355,612,225.75	303,648,415.38	17,969,337.53	217,774.79	255,292.29	1,073,906,644.18
2009	1,966,648.43	8,633,981.03	54,306,307.54	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	82,296,381.83
Post-1996	29,141,944.89	35,131,453.99	601,777,935.45	766,576.44	248,029,482.24	132,578,594.30	393,531,779.14	381,601,955.66	22,513,885.06	3,843,307.38	4,525,999.73	1,853,442,914.29
Grand Total	68,450,591.48	39,508,346.51	700,486,640.91	27,134,366.96	349,291,739.58	211,534,674.05	394,349,689.95	387,545,579.18	29,307,957.82	9,448,797.99	24,222,393.36	2,241,280,777.78

Worksheet 9

PSNH

Substations and Lines

PTF Investment as of 12/31/09 (101 + 106)

	350	352	353	354	355	356	357	358	359	361	362	Grand Total
1975 + PRIOR	6,677,178.25	1,621,748.44	11,302,843.45	4,984,250.97	14,254,840.62	13,260,590.24	0.00	0.00	126,989.38	784,757.72	1,175,304.13	54,188,503.19
1976	40,052.68	2,107.57	372,533.91	0.00	146,865.11	55,339.81	0.00	0.00	0.00	86,597.09	151,471.48	854,967.65
1977	23,877.28	0.00	73,817.97	0.00	337,362.92	302,087.83	0.00	0.00	0.00	3,873.48	40,487.27	781,506.75
1978	139,193.33	3,229.14	256,480.11	0.00	111,091.68	74,800.11	0.00	0.00	0.00	29,108.33	49,066.51	662,969.20
1979	8,075.01	1,061.97	230,938.76	0.00	22,896.88	8,952.07	0.00	0.00	0.00	130,250.42	83,402.70	485,577.81
1980	1,509,193.04	23,511.16	960,628.38	3,683,253.81	130,557.04	2,447,303.65	0.00	0.00	468,079.93	0.00	3,739.86	9,226,266.86
1981	0.00	0.00	40,396.50	0.00	55,105.42	8,828.28	0.00	0.00	0.00	6,452.11	3,575.06	114,357.37
1982	18.16	0.00	40,380.30	0.00	119,784.62	9,531.48	0.00	0.00	15,557.34	25,919.80	50,520.23	261,711.93
1983	3,022,629.15	4,803.81	553,634.31	0.00	6,712,752.36	4,147,566.73	0.00	0.00	58,959.34	95,236.95	2,398.51	14,597,981.15
1984	1,251.27	0.00	285,953.32	0.00	31,174.37	3,868.27	0.00	0.00	0.00	169,484.43	172,954.83	664,686.50
1985	41.35	0.00	71,098.00	0.00	180,351.54	30,518.62	0.00	0.00	0.00	11,053.85	54,421.92	347,485.29
1986	0.00	575.06	434,781.12	0.00	284,255.28	131,783.31	0.00	0.00	0.00	0.00	10,790.16	862,184.93
1987	453,534.74	0.00	99,626.48	0.00	139,220.19	25,572.65	0.00	0.00	3,785.03	8,147.79	42,050.76	771,937.63
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	13,036.43	3,439,896.06
1989	14,647.25	0.00	187,067.04	0.00	375,064.19	91,236.57	0.00	0.00	1,113.97	567,425.46	625,361.96	1,861,916.44
1990	0.00	5,566.96	165,557.25	0.00	313,894.77	10,127.91	0.00	0.00	3,015.40	0.00	6,294.38	504,456.67
1991	5,325.56	0.00	33,682.54	0.00	321,114.13	59,368.51	0.00	0.00	6,908.16	13,872.23	26,326.91	466,598.05
1992	381.53	0.00	33,228.76	0.00	404,513.81	58,366.32	0.00	0.00	0.00	2,009.94	25,993.10	524,493.47
1993	813,715.17	0.00	435,499.84	0.00	1,506,902.88	1,564,686.24	0.00	0.00	0.00	28,196.47	80,153.53	4,429,154.13
1994	302,587.45	24,037.53	92,725.67	0.00	364,912.43	67,024.43	0.00	0.00	10,622.94	32,094.12	6,405.45	900,410.02
1995	0.00	0.00	97,657.99	0.00	105,310.72	147,016.99	0.00	0.00	0.00	0.00	14,950.86	364,936.56
1996	12,216.10	0.00	441,753.36	0.00	60,177.02	(202,468.68)	0.00	0.00	8,428.10	32,409.03	80,389.66	432,904.60
Pre-1997	13,027,526.92	1,686,641.63	16,210,730.28	9,633,353.29	26,934,274.74	23,802,930.87	0.00	0.00	703,459.59	2,026,889.23	2,719,095.69	96,744,902.24
1997	16,059.00	0.00	166,533.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	94,372.72	276,964.75
1998	0.00	0.00	180,500.93	0.00	34,083.95	4,290.69	0.00	0.00	0.00	0.00	1,664.77	220,540.34
1999	0.00	0.00	469,871.03	0.00	435,301.73	38,462.21	0.00	0.00	0.00	5,461.52	14,356.64	963,453.13
2000	1,591.56	0.00	57,006.27	0.00	601,181.18	118,478.75	0.00	0.00	0.00	9,009.43	2,313.72	789,580.91
2001	1,850.00	0.00	1,391,953.03	0.00	1,970,547.07	1,012,304.30	0.00	0.00	0.00	106,688.04	29,316.27	4,512,658.71
2002	17.06	51,812.72	2,287,816.42	0.00	1,323,131.65	340,583.63	0.00	0.00	0.00	0.00	29,495.81	4,032,857.29
2003	495,842.43	139,883.66	13,838,789.15	0.00	3,907,008.02	1,490,848.56	0.00	0.00	0.00	290,893.62	230,291.38	20,393,556.81
2004	510,898.88	897,397.69	16,867,495.28	0.00	2,905,956.61	948,832.29	0.00	0.00	0.00	45,891.82	159,563.98	22,336,036.56
2005	607,230.03	1,099,944.80	13,031,748.92	0.00	3,316,986.24	1,562,108.85	0.00	0.00	0.00	1,159,751.11	138,884.24	20,916,654.19
2006	361,997.42	413,745.57	14,307,997.78	0.00	4,434,760.65	1,806,371.74	0.00	0.00	0.00	268,080.09	443,427.20	22,036,380.45
2007	3,338.33	416,869.30	21,227,098.90	48,014.31	17,720,558.48	4,431,233.22	0.00	0.00	0.00	525,633.25	844,557.05	45,217,302.84
2008	5,379.80	8,948,645.80	51,619,586.37	23,769.94	7,818,068.35	4,779,229.88	0.00	0.00	0.00	328,489.15	555,684.16	74,078,853.45
2009	91,869.99	3,863,172.71	46,525,384.26	0.00	7,607,787.78	9,350,525.52	0.00	0.00	7,337.13	0.00	165,144.35	67,611,221.74
Post-1996	2,096,074.48	15,831,472.25	181,971,781.36	71,784.25	52,075,371.71	25,883,269.64	0.00	0.00	7,337.13	2,739,898.04	2,709,072.31	283,386,061.17
Grand Total	15,123,601.40	17,518,113.88	198,182,511.64	9,705,137.54	79,009,646.45	49,686,200.51	0.00	0.00	710,796.72	4,766,787.27	5,428,168.00	380,130,963.41

Western Massachusetts Electric Company

Worksheet 10

Substations and Lines

PTF Investment as of 12/31/09 (101 + 106)

	350	352	353	354	355	356	357	358	359	361	362	Grand Total
1975 + PRIOR	9,120,524.68	1,230,749.82	14,438,297.25	1,035,870.02	6,446,426.26	10,348,107.46	31,742.27	1,169,976.09	-	1,555,064.08	2,434,037.82	47,810,795.74
1976	3,614.90	30.98	381,927.32	-	1,378,475.90	1,207,478.48	-	-	-	19,824.85	33,896.37	3,025,248.80
1977	24,338.31	2,000.94	129,316.93	113,901.57	2,058,031.62	2,288,786.11	-	-	-	12,202.17	338,368.23	4,966,945.87
1978	-	-	15,229.33	-	-	7,536.32	-	-	-	115,849.93	35,200.15	173,815.73
1979	10,284.94	-	447,849.33	-	178,455.10	86,353.76	-	-	5,614.05	-	8,629.78	737,186.96
1980	1,449.53	-	806,879.08	-	-	1,909.38	-	-	-	1,211.92	259,223.34	1,070,673.25
1981	12,424.35	-	129,053.97	-	-	-	-	-	-	-	61,224.61	202,702.93
1982	50,999.36	-	282,026.93	-	-	13,901.64	-	-	-	-	93,764.05	440,691.98
1983	-	15,300.56	186,122.26	-	-	-	-	-	-	14,888.11	99,832.01	316,142.94
1984	73,847.45	-	834,923.74	-	72,572.55	132,518.95	-	-	-	29,585.95	323,277.91	1,466,726.55
1985	199,055.53	17,419.40	66,227.75	-	40,356.20	10,366.45	-	-	-	6,774.91	62,967.92	403,168.16
1986	-	-	196,344.02	-	-	61,388.46	-	-	-	8,069.36	-	265,801.84
1987	1,537.04	-	99,875.80	-	-	158,226.93	-	-	-	28,132.36	107,319.27	395,091.40
1988	1,125.58	-	622,196.28	-	39,865.01	33,013.71	-	-	25,912.84	-	246,955.57	969,068.99
1989	1,477.73	-	198,274.28	-	362,317.19	113,378.48	-	-	-	10,483.12	8,753.84	694,684.64
1990	9,163.43	-	101,870.56	-	105,712.74	34,978.81	-	-	-	-	1,918.50	253,644.04
1991	-	-	84,104.84	-	266,055.97	133,187.39	-	-	-	712.88	3,136.14	487,197.22
1992	-	-	283,757.42	-	183,464.03	15,808.38	-	-	-	-	81,456.54	564,486.38
1993	-	-	137,078.90	-	52,120.46	290,094.29	-	-	-	-	38,019.57	517,313.22
1994	-	22,064.09	18,626.44	-	167,421.48	233,890.68	-	-	-	-	10,390.05	452,392.74
1995	-	-	100,161.98	-	3,830.17	-	-	27,888.96	-	22,974.76	-	154,855.87
1996	-	16,396.08	-	-	-	213,574.66	-	-	-	20,623.63	11,457.09	262,051.46
Pre-1997	9,509,842.83	1,303,961.86	19,560,144.43	1,149,771.59	11,355,104.68	15,384,500.34	31,742.27	1,197,865.05	31,526.89	1,846,398.03	4,259,828.75	65,630,686.72
1997	-	-	1,369,936.30	-	414,195.88	2,977,961.82	-	-	-	12,754.66	2,194.99	4,777,043.65
1998	15,233.06	-	18,691.00	-	-	-	-	-	-	11,942.79	58,607.19	104,474.03
1999	-	-	1,756,926.89	-	1,928,894.28	2,775,537.62	-	-	-	-	4,452.17	6,465,810.95
2000	-	2,485.74	206,928.05	-	61,315.74	-	-	-	25,475.05	-	-	296,204.58
2001	-	-	1,969,495.00	-	13,159.84	95,408.84	-	-	-	-	50,054.31	2,128,117.99
2002	-	77,480.18	3,257,381.14	-	388,521.22	90,676.02	-	-	-	-	54,906.42	3,868,964.98
2003	-	-	2,296,373.83	-	67,136.37	9,154.96	-	-	-	-	31,764.24	2,404,429.40
2004	-	45,747.79	5,111,711.20	-	854,457.36	148,753.14	-	-	4,668.80	78,416.56	166,076.11	6,409,830.96
2005	-	54,332.71	7,815,481.79	-	204,792.77	-	-	-	-	9,559.57	9,733.66	8,093,900.51
2006	-	-	8,655,706.98	-	502,006.52	282,562.52	-	-	22,539.43	35,289.37	140,072.68	9,638,177.50
2007	899.11	-	6,690,718.81	-	248,772.49	691,401.78	-	-	4,728.76	26,899.16	-	7,663,420.11
2008	1,762.03	69,086.70	6,275,410.50	-	4,056,325.76	373,039.45	-	-	12,386.05	849.45	183,207.94	10,972,067.88
2009	-	1,741,472.83	10,045,398.68	-	9,657,458.16	5,886,137.68	-	-	-	146,742.47	43,363.91	27,520,573.74
Post-1996	17,894.20	1,990,605.96	55,470,160.16	-	18,397,036.39	13,330,633.83	-	-	69,798.09	322,454.04	744,433.63	90,343,016.30
Grand Total	9,527,737.03	3,294,567.82	75,030,304.59	1,149,771.59	29,752,141.07	28,715,134.17	31,742.27	1,197,865.05	101,324.98	2,168,852.07	5,004,262.38	155,973,703.03

CL&P RSP INVESTMENT BY PLANT ACCOUNT AT 12-31-09					Worksheet 11
		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	11,112,420.20	293,451.33	10,818,968.87	
	2007	10,855,862.16	383,774.48	10,472,087.68	
	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		27,761,049.26	883,139.49	26,877,909.78	
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	66,604,659.73	5,640,491.54	60,964,168.20	
	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		428,636,495.58	24,028,341.88	404,608,153.70	
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	79,576,977.96	7,121,223.60	72,455,754.35	
	2008	113,343,455.32	6,098,601.06	107,244,854.25	
355 Total		213,171,431.31	15,882,469.68	197,288,961.64	
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	35,626,404.42	2,599,955.49	33,026,448.93	
	2008	59,519,587.80	2,610,920.15	56,908,667.65	
356 Total		103,462,773.67	6,145,270.38	97,317,503.29	
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	355,612,225.75	8,591,506.06	347,020,719.69	
357 Total		393,395,146.11	10,277,837.24	383,117,308.87	
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	303,648,415.38	5,640,016.09	298,008,399.29	
358 Total		381,196,297.86	6,964,898.37	374,231,399.50	
359	2006	3,919,366.48	202,669.92	3,716,696.56	
	2008	17,924,658.94	406,383.76	17,518,275.18	
359 Total		21,844,025.42	609,053.68	21,234,971.75	
Grand Total		1,594,157,157.01	66,660,408.81	1,527,496,748.20	

PSNH RSP INVESTMENT BY PLANT ACCOUNT AT 12-31-09					Worksheet 12
		Data			
Plant A/C	Year	Sum of Gross Plant2	Sum of Accum Depr2	Sum of Net Plant2	
350	2007	3,343.34	0.00	3,343.34	
350 Total		3,343.34	0.00	3,343.34	
352	2006	401,937.67	24,131.35	377,806.32	
	2007	416,869.30	17,916.45	398,952.85	
	2008	8,203,611.74	211,981.17	7,991,630.57	
352 Total		9,022,418.71	254,028.97	8,768,389.74	
353	2004	14,069,510.91	1,497,980.55	12,571,530.37	
	2005	5,432,171.26	483,077.01	4,949,094.25	
	2006	11,532,024.41	814,739.14	10,717,285.27	
	2007	14,237,722.52	734,103.52	13,503,619.00	
	2008	38,047,591.52	1,203,127.23	36,844,464.28	
353 Total		83,319,020.62	4,733,027.45	78,585,993.17	
355	2004	1,684,384.08	235,073.75	1,449,310.33	
	2005	145,459.57	16,546.90	128,912.67	
	2006	3,181,946.87	281,275.55	2,900,671.32	
	2007	16,914,322.63	1,071,465.35	15,842,857.28	
	2008	4,034,500.63	154,844.09	3,879,656.54	
355 Total		25,960,613.78	1,759,205.64	24,201,408.14	
356	2004	741,149.36	105,581.70	635,567.66	
	2005	38,143.60	4,299.20	33,844.40	
	2006	1,568,300.13	133,042.20	1,435,257.93	
	2007	4,126,890.94	242,810.83	3,884,080.11	
	2008	1,796,756.10	62,259.04	1,734,497.06	
356 Total		8,271,240.13	547,992.97	7,723,247.16	
Grand Total		126,576,636.58	7,294,255.03	119,282,381.55	

WMECO RSP INVESTMENT BY PLANT ACCOUNT AT 12-31-09					Worksheet 13
		Data			
Plant A/C	Year	Sum of Gross Plant2	Sum of Accum Depr2	Sum of Net Plant2	
353	2004	3,552,604.47	403,393.17	3,149,211.30	
	2005	3,005,184.23	282,711.15	2,722,473.08	
	2006	4,654,941.92	344,795.46	4,310,146.46	
	2008	1,095,892.69	35,602.47	1,060,290.22	
353 Total		12,308,623.31	1,066,502.25	11,242,121.06	
Grand Total		12,308,623.31	1,066,502.25	11,242,121.06	

CL&P ADVANCED TECHNOLOGY INVESTEMENT AT 12-31-09						Worksheet 14
Work Order Description	Plant A/C	Work Order Inservice Year	Gross Plant	Accum Depr.	Net Plant	
MN 345KV SEG1 BESECK SWITCH STATION	353	2007	217,350.79	10,908.48	206,442.31	
MN 345KV SEG 3 ROW EASEMENTS	350	2007	154,082.53	5,506.98	148,575.55	
MN 345KV SEG 3 ROW EASEMENTS	350	2007	318,714.78	11,391.02	307,323.76	
MN 345KV SEG 4 ROW EASEMENTS	350	2007	832,242.54	29,744.74	802,497.80	
MN 345KV SEG 4 ROW EASEMENTS	350	2007	1,969,149.47	70,378.33	1,898,771.14	
MN 345KV SEG 4 ROW EASEMENTS	350	2007	1,100,725.15	39,340.43	1,061,384.72	
MN 345KV SEGMENT 2 EAST DEVON S/S-115KV WORK	353	2008	244,615.17	7,621.70	236,993.47	
MN 345KV SEGMENT 2 EAST DEVON S/S-345KV WORK	353	2008	157,306.34	4,901.34	152,405.00	
MN 345KV SEGMENT 2 EAST DEVON S/S-AUTOS	353	2008	133,987.72	4,174.78	129,812.94	
MN 345KV SEGMENT 2 EAST DEVON S/S-AUTOS	353	2008	170,398.48	5,309.26	165,089.22	
MN 345KV SEGMENT 3 EAST DEVON TO SINGER	357	2008	21,418,950.91	289,851.31	21,129,099.60	
MN 345KV SEGMENT 3 EAST DEVON TO SINGER	358	2008	30,423,166.89	735,016.41	29,688,150.48	
MN 345KV SEGMENT 4 SINGER TO NORWALK	357	2008	209,539,016.04	5,062,412.34	204,476,603.70	
MN 345KV SEGMENT 4 SINGER TO NORWALK	358	2008	136,771,386.71	1,850,854.70	134,920,532.01	
MN 345KV SEGMENT 4 NORWALK SS	353	2008	131,301.84	4,091.09	127,210.75	
MN 345KV SEGMENT 4 NORWALK SS	353	2008	87,531.03	2,727.28	84,803.75	
MN 345KV SEGMENT 4 NORWALK SS	353	2008	272,633.29	8,494.68	264,138.61	
MN 345KV SEGMENT 4 NORWALK SS	353	2008	181,751.99	5,663.01	176,088.98	
MN 345KV SEGMENT 4 NORWALK SS_SHUNT REACTORS	353	2008	686,611.62	21,393.38	665,218.24	
MN 345KV SEGMENT 4 NORWALK SS_SHUNT REACTORS	353	2008	7,217,304.26	224,876.12	6,992,428.14	
MN 345KV SEGMENT 4 NORWALK SS_SHUNT REACTORS	353	2008	65,604.29	2,044.09	63,560.20	
			412,093,831.84	8,396,701.47	403,697,130.37	

Norwood Municipal Light Department

Sheet: Input Panel | Input Panel

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

Shading denotes an input

Submitted on:	05/21/2009
Revenue Requirements for (year):	2009
Customer:	Norwood Municipal Light Department
Customer's NABs Number:	15-586-6304
Name of Participant responsible for customer's billing:	Malcolm McDonald
DUNs number of Participant responsible for customer's billing:	15-586-6304

	Pre-97 Revenue Requirements		Post-96 Revenue Requirements	
Total of Attachment F - Sections A through I =		(a)	2,487,016	(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)	2,487,016	(j)=(f)-(g)+(h)+(i)
Forecasted Incremental Transmission Revenue Requirements			0	(m)
Annual True-up			3,491	(n)
Interest Charge on Annual True-up	-	(l)	171	(o)
Total = (e) + (j) + (k) + (l) + (m) + (n) + (o)	0	(p)	2,490,678	(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:			2,490,678	(r) = (p)+(q)

Norwood Municipal Light Department

RNS Rate

Annual Revenue Requirements of pre-1997 & post-1996 PTF
for costs in 2008 06/09-05/10

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	Pre 1997	Post 1996	Reference
1	Transmission Plant	I (A)(1)(a)	0	13,243,848	Worksheet 3, line 1 column 5
2	General Plant	I (A)(1)(b)	0	220,822	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	13,464,670	
5	Accumulated Depreciation	I (A)(1)(d)	0	2,797,546	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	10,667,124	
10	Prepayments	I (A)(1)(h)	0	4,589	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	35,600	Worksheet 3, line 24 column 5
13	Total Investment Base (Line 9+11+12+13)		0	10,707,313	
	II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	I (A)	0	856,585	Worksheet 2
15	Depreciation Expense	I (B)	0	390,702	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	18,975	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	I (G)	0	81,522	Worksheet 4, line 13 column 5
21	Administrative & General Expense	I (H)	0	203,274	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	2,483,525	

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 2009

1	2007 Actual Annual RR			0	2,487,016	Input Panel Subtotals
2	2007 Est. Transmission Revenue Requirements (as billed)	6/09-05/10	Appendix C	0	2,483,525	ATRR - Prior Year
3	True-up (Over)/Under (Line 1 - Line 2)			0	3,491	

	(Overcollection)/Undercollection
Pre'97	$0
Post'96	$3,491

Initial Billing Period	Pre 1997 Balance	Post 1996 Balance	FERC Monthly Interest Rate	Pre 1997 Interest	Post 1996 Interest
June 2008	$0	$3,491	0.56%	$0	$20
July 2008	0	3,511	0.45%	0	$16
August 2008	0	3,511	0.45%	0	$16
September 2008	0	3,511	0.44%	0	$15
October 2008	0	3,558	0.42%	0	$15
November 2008	0	3,558	0.41%	0	$15
December 2008	0	3,558	0.42%	0	$15
January 2009	0	3,602	0.38%	0	$14
February 2009	0	3,602	0.34%	0	$12
March 2009	0	3,602	0.38%	0	$14
April 2009	0	3,642	0.28%	0	$10
May 2009	0	3,642	0.29%	0	$11
		Total Interest		$0	$171
		True-Up		$0	$3,491
		Total TU & Int		**$0**	**$3,662**

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 21, 2010
Revenue Requirements for (year):	Calendar Year 2009
Customer:	Norwood Municipal Light Department
Customer's NABs Number:	
Name of Participant responsible for customer's billing:	Malcolm McDonald
DUNs number of Participant responsible for customer's billing:	15-586-6304

		Pre-97 Revenue Requirements		Post-97 Revenue Requirements	
Total of Attachment F - Sections A through I	=		(a)	2,487,016	(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)	2,487,016	(j)

Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:	2,487,016	(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)	2,487,016	(l)=(k)+(b)+(g)-(h)

Calendar Year 2009

Shading denotes an input

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	Norwood	Reference
1	Transmission Plant	(A)(1)(a)	13,243,847	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	271,790	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)		13,515,637	
5	Accumulated Depreciation	(A)(1)(d)	3,205,899	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)		10,309,738	
10	Prepayments	(A)(1)(h)	3,878	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)	37,613	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		10,351,229	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	828,098	Worksheet 2
15	Depreciation Expense	(B)	401,234	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)	24,315	*Worksheet 4, line 17 column 5*
20	Operation & Maintenance Expense	(G)	62,669	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	238,233	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)		2,487,016	

Norwood Municipal Light Department
Annual Revenue Requirements
Calendar Year 2009

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

$= \dfrac{(0.0000 + (0 + 0) / 10,351,229) \times 0)}{(1 - 0)}$

$= 0.0000000$

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

$= \dfrac{(0.0000 + (0 + 0) / 10,351,229) + 0.0000000)^{*} \ 0}{(1 - 0)}$

$= 0.0000000$

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

		(PTF)	
INVESTMENT BASE	$	10,351,229	From Worksheet 1
x Cost of Capital Rate		0.0800000	
= Investment Return and Income Taxes		828,098	To Worksheet 1

Sheet: Worksheet 3a

Norwood Municipal Light Department

Calendar Year 2009

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	$ 13,243,847		13,243,847		13,243,847	Line 1, Worksheet 5
2	General Plant	3,694,836	9.2759% (a)	342,729	79.3018%	271,790	Page 8B line 29(g)
3	Total (line 1+2)			13,586,576		13,515,637	
4	Transmission Plant Held for Future Use	0		0	79.3018%	0	None known
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	3,943,730		3,943,730	79.3018%	3,127,449	Page 8A, line 31(g) less Page 16, line 31(g)
6	General Plant Accum.Depreciation	1,066,489	9.2759% (a)	98,926	79.3018%	78,450	Page 8B, line 29(g) less Page 17, line 29(g)
7	Total (line 5+6)			4,042,656		3,205,899	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	0	30.8442% (c)	0	79.3018%	0	None known
9	Accumulated Deferred Taxes (190)	0	30.8442% (c)	0	79.3018%	0	None known
10	Total (line 8+9)			0		0	
11	Transmission loss on Reacquired Debt	0	30.8442% (c)	0	79.3018%	0	None known
	Other Regulatory Assets						
12	FAS 106	0	9.2759% (a)	0	79.3018%	0	None known
13	FAS 109	0	30.8442% (c)	0	79.3018%	0	None known
14	Other Regulatory Liabilities (254.DK)	0	30.8442% (c)	0	79.3018%	0	
15	Total (line 12+13+14)			0		0	
16	Transmission Prepayments	52,712	9.2759% (a)	4,890	79.3018%	3,878	Assumed none
17	Transmission Materials and Supplies	0		0	79.3018%	0	Assumed none
18	Cash Working Capital						
19	Operation & Maintenance Expense					62,669	Worksheet 1, Line 20
20	Administrative & General Expense					238,233	Worksheet 1, Line 21
21	Transmission Support Expense					0	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					300,902	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					37,613	

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

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	495,845				495,845	79.3018%	393,214	Page 16, line 31(d)
2	General Depreciation	109,020		9.2759%	(a)	10,113	79.3018%	8,020	Page 17, line 29(d)
3	Total (line 1+2)					505,958		401,234	
4	Amortization of Loss on Reacquired Debt	0		30.8442%	(c)	0	79.3018%	0	None known
5	Amortization of Investment Tax Credits	0		30.8442%	(c)	0	79.3018%	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	3,608,998				3,608,998	0.793018	2,862,000	Page 40, line 50(b)
10	Transmission of Electricity by Others - #565	3,234,044				3,234,044	0.793018	2,564,655	Page 40, line 38(b)
11	Load Dispatching - #561	0				0	0.793018	0	Page 40, line 34(b)
12	**Station Expenses & Rents - #562 / #567	295,928				295,928	0.793018	234,676	Page 40, line 35(b) 40(b)
13	O&M less lines 10, 11 & 12	79,026				374,954	79.3018%	62,669	
	Transmission Administrative and General								
14	Administrative and General	2,896,043							Page 42, line 6(b)
15	*less Property Insurance (#924)*	153,998							Page 41, line 47(b)
16	*less Regulatory Commission Expenses (#928)*	*0*							Page 41, line 50(b)
17	*less General Advertising Expense (#930.1)*	15,474							*assumed none*
18	Subtotal [line 14 minus (15 thru 17)]	2,726,571		9.2759%	(a)	252,914	79.3018%	200,565	
19	*PLUS Property Insurance alloc. using Plant Allocatior*	*153,998*		*30.8442%*	*(c)*	47,499	79.3018%	37,668	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	*0*		*30.8442%*	*(c)*	0	79.3018%	0	
21	*PLUS Trans. Related General Advertising Expense*	*0*		*30.8442%*	*(c)*	0	79.3018%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*2,880,569*				*300,413*		*238,233*	
23	*Payroll Tax Expense*	330,541		*9.2759%*	*(a)*	*30,661*	*79.3018%*	*24,315*	

(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

Sheet: Worksheet 5

Shading denotes an input

Calendar Year 2009

Line No.		Norwood	Mass DTE AR Reference
	PTF Transmission Plant Allocation Factor		
1	PTF Transmission Investment	13,243,847	See Worksheet
2	Total Transmission Investment	16,700,573	Page 8A, line 31(g)
3	Percent Allocation (Line 1/Line 2)	79.3018%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	239,701	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)	239,701	
7	Total Wages and Salaries	3,004,922	Page 42, line 24 (c)
8	Administrative and General Wages and Salaries	420,808	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)	2,584,114	
11	Percent Allocation (Line 6/Line 10)	9.2759%	
	Plant Allocation Factor		
12	Total Transmission Investment	16,700,573	Line 2
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	342,729	*Worksheet 3, Line 2*
14	*= Revised Numerator (Line 12 + Line 13)*	17,043,302	
15	Total Plant in Service	55,256,036	Page 8B, line 30 (g)
16	Percent Allocation (Line 14 / Line 15)	30.8442%	

Sheet: Worksheet 6

Affiliated Company Wages and Salaries

Shading denotes an input

Calendar Year 2009

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

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

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

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

NSTAR Electric Company

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:	5/14/2010
Revenue Requirements for (year):	2009
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	=	52,925,363	(a)	92,062,436	(f)
Total of Attachment F - Section J - Support Revenue		(742,843)	(b)	-	(g)
Total of Attachment F - Section K - Support Expense		3,042,001	(c)	-	(h)
Total of Attachment F - Section L through O		(108,042)	(d)	(181,658)	(i)
Sub Total - Sum (A through I) - J + K + (L through O)		55,116,478	(e)=(a)-(b)+(c)+(d)	91,880,778	(j)=(f)-(g)+(h)+(i)
Forecasted Incremental Transmission Revenue Requirements		-	n/a	4,487,271	(m)
Annual True-up		(1,713,324)	(k)	(4,929,981)	(n)
Interest Charge on Annual True-up		(57,270)	(l)	(164,791)	(o)
Total = (e) + (j) + (k) + (l) + (m) + (n) + (o)		53,345,884	(p)	91,273,277	(q)

Annual Projected 2009 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: $ 144,619,161 (r) = (p)+(q)

NSTAR Electric Company
Annual Revenue Requirements of pre-1997 & post-1996 PTF
for costs in 2009 06/09-05/10

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	Pre 1997	Post 1996	Reference
1	Transmission Plant	I (A)(1)(a)	$ 400,782,972	$ 673,860,892	Page 4, line 2
2	General Plant	I (A)(1)(b)	3,850,241	6,473,645	Page 4, line 3
3	Plant Held For Future Use	I (A)(1)(c)	-	798,633	Page 4, line 5
4	Total Plant		$ 404,633,213	$ 681,133,170	Sum Lines 1 thru 3
5	Accumulated Depreciation	I (A)(1)(d)	(110,775,249)	(186,253,192)	Page 4, line 9
6	Accumulated Deferred Income Taxes	I (A)(1)(e)	(78,468,830)	(131,934,437)	Page 4, line 14
7	Loss On Reacquired Debt	I (A)(1)(f)	1,804,218	3,033,541	Page 4, line 15
8	Other Regulatory Assets	I (A)(1)(g)	2,236,491	3,760,350	Page 4, line 20
9	Net Investment		$ 219,429,843	$ 369,739,432	Sum Lines 4 thru 8
10	Prepayments	I (A)(1)(h)	147,386	247,808	Page 4, line 21
11	Materials & Supplies	I (A)(1)(i)	629,267	1,058,025	Page 4, line 22
12	Cash Working Capital	I (A)(1)(j)	1,217,010	1,563,020	Page 4, line 29
13	Total Investment Base		$ [illegible]	$ 5	Sum Lines 9 thru 12
	II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	I (A)	$ 29,906,568	$ 53,359,530	Page 3, Line 26
15	Depreciation Expense	I (B)	8,790,537	14,780,067	Page 5, Line 4
16	Amortization of Loss on Reacquired Debt	I (C)	193,664	325,618	Page 5, Line 5
17	Investment Tax Credit	I (D)	(110,972)	(186,585)	Page 5, Line 6
18	Property Taxes	I (E)	6,483,615	10,901,298	Page 5, Line 8
19	Payroll Tax Expense	I (F)	225,027	378,351	Page 5, Line 24
20	Operation & Maintenance Expense	I (G)	4,422,178	7,435,278	Page 5, Line 14
21	Administrative & General Expense	I (H)	3,014,747	5,068,879	Page 5, Line 23
22	Transmission Related Integrated Facilities Charge	I (I)	-	-	
23	Transmission Support Revenue	I (J)	(742,843)	-	Page 7, Line 13
24	Transmission Support Expense	I (K)	3,042,001	-	Page 7, Line 13
25	Transmission Related Expense from Generators	I (L)	-	-	
26	Transmission Related Taxes and Fees Charge	I (M)	-	-	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	I (N)	(108,042)	(181,658)	OATT Schedule 8 TOUT
28	Transmission Rents Received from Electric Property	I (O)	-	-	
29	Total Revenue Requirements		$ 55,116,478	$ 91,880,778	Sum Lines 14 thru 28
	III. <u>CURRENT CALENDAR YEAR ESTIMATED INCREMENTAL REVENUE REQUIREMENT</u>				
30	Carrying Charge Factor Base Revenue Requirement Numerator			$ 91,880,778	Line 29
31	Post-2003 Enhanced Return Addition to Revenue Requirement			-	
32	Total Post-96 PTF Revenue Requirement			$ 91,880,778	Sum Lines 30 thru 31
33	Post-96 PTF Transmission Plant in Service			$ 673,860,892	Line 1
34	Post-96 Carrying Charge Factor (Post-96 CCF)			0.136349771	Line 32 / Line 33
35	Forecasted Post-96 PTF Plant Additions			$ 32,910,000	
36	Forecasted Post-96 Localized PTF Plant Additions			-	
37	Forecasted Post-96 Pool-Supported PTF Plant Additions			32,910,000	Sum Lines 35 thru 36
38	Post-96 Estimated Incremental Revenue Requirement			$ 4,487,271	Line 34 * Line 37

NSTAR Electric Company
FERC Interest Calculation associated with Under / (Over)
True-up and Interest Calculation 06/09-05/10

1	2009 Est. Transmission Revenue Requirements (as billed)	6/09-05/10	Appendix C	[illegible]		ATRR - Prior Year
2	2009 Actual Annual RR			[illegible]		Input Panel Subtotals
3	True-up Over/(Under) (Line 1 - Line 2)			1,713,324	4,929,981	

	(Overcollection)/Undercollection
Pre'97	($1,713,324)
Post'96	($4,929,981)

Initial Billing Period	Pre 1997 Balance	Post 1996 Balance	FERC Monthly Interest Rate	Pre 1997 Interest	Post 1996 Interest
June 2009	$ [illegible]	$	0.28%	$ (4,797)	$ (13,804)
July 2009	(1,718,121)	(4,943,784)	0.28%	(4,811)	(13,843)
August 2009	(1,718,121)	(4,943,784)	0.28%	(4,811)	(13,843)
September 2009	(1,718,121)	(4,943,784)	0.27%	(4,639)	(13,348)
October 2009	(1,732,382)	(4,984,818)	0.28%	(4,851)	(13,957)
November 2009	(1,732,382)	(4,984,818)	0.27%	(4,677)	(13,459)
December 2009	(1,732,382)	(4,984,818)	0.28%	(4,851)	(13,957)
January 2010	(1,746,760)	(5,026,192)	0.28%	(4,891)	(14,073)
February 2010	(1,746,760)	(5,026,192)	0.25%	(4,367)	(12,565)
March 2010	(1,746,760)	(5,026,192)	0.28%	(4,891)	(14,073)
April 2010	(1,760,909)	(5,066,904)	0.27%	(4,754)	(13,681)
May 2010	(1,760,909)	(5,066,904)	0.28%	(4,931)	(14,187)
		Total Interest		$ (57,270)	$ (164,791)
		True-Up		(1,713,324)	(4,929,981)
		Total TU & Int		**$(1,770,594)**	**$ (5,094,772)**

NSTAR Electric Company

2010 Forecast PTF Capital Additions

Line #	Project #	Description		Amount
1	04394	Line 433-507 Relocation	$	403,000
2	07318	Carver Sta (2007 portion)		64,000
3	07338	STA 330 - 345kV Project Ph.II		19,000
4	08239	Barnstable STATCON		16,000
5	09102	Mystic East Bus		530,000
6	09103	Mystic 115 cbs station 250		36,000
7	09104	Edgar 115 reactors		132,000
8	09275	Holbrook Breaker 11		188,000
9	09276	Walpole site support- spare reactor		2,653,000
10	09286	NGRID Line 349 X&Y Station Work at Mystic Station		31,000
11	09308	D21 and Line 12 high speed relays		318,000
12	09309	BPS Upgrade Replace 3 breakers sta 148		2,000
13	09310	BPS Upgrade Replace 3 breakers sta 282		19,000
14	09311	BPS Station work- Tremont Station		7,662,000
15	09314	Transmission Line 325 Infrastructure		910,000
16	09318	Cross arms (319.211-508,240-510		133,000
17	09360	Transmission Line 325 Infrastructure Station Work		89,000
18	10101	Mystic Sta 250 Brk Repl 2010		1,322,000
19	10186	K St. Breaker and Tie Bus		2,493,000
20	10199	STA 726 115kV Transmission Breaker Replacements		945,000
21	Various	Not-In ISO-NE Plan		14,945,000
22		Total Forecast PTF Additions	$	32,910,000

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Submitted on:	May 14, 2010
Revenue Requirements for (year):	2009
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	=	$ 52,925,363	(a)	$ 92,062,436	(f)
Total of Attachment F - Section J - Support Revenue	=	742,843	(b)	-	(g)
Total of Attachment F - Section K - Support Expense	=	3,042,001	(c)	-	(h)
Total of Attachment F - Sections L-O	=	(108,042)	(d)	(181,658)	(i)
Sub Total - Sum (A through H) - J + K+ (L through O)	=	$ 55,116,478	(e)=(a)-(b)+(c)+(d)	$ 91,880,778	(j)
Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:				$ 146,997,256	(k) = (e) + (j)

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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)	$ 400,782,972	$ 673,860,892	Page 4, line 2
2	General Plant	II (A)(1)(b)	3,850,241	6,473,645	Page 4, line 3
3	Plant Held For Future Use	II (A)(1)(c)	-	798,633	Page 4, line 5
4	Total Plant		404,633,213	681,133,170	Sum Lines 1 thru 3
5	Accumulated Depreciation	II (A)(1)(d)	(110,775,249)	(186,253,192)	Page 4, line 9
6	Accumulated Deferred Income Taxes	II (A)(1)(e)	(78,468,830)	(131,934,437)	Page 4, line 14
7	Loss On Reacquired Debt	II (A)(1)(f)	1,804,218	3,033,541	Page 4, line 15
8	Other Regulatory Asssets	II (A)(1)(g)	2,236,491	3,760,350	Page 4, line 20
9	Net Investment		219,429,843	369,739,432	Sum Lines 4 thru 8
10	Prepayments	II (A)(1)(h)	147,386	247,808	Page 4, line 21
11	Materials & Supplies	II (A)(1)(II)	629,267	1,058,025	Page 4, line 22
12	Cash Working Capital	II (A)(1)(j)	1,217,010	1,563,020	Page 4, line 29
13	Total Investment Base		$ 221,423,507	$ 372,608,285	Sum Lines 9 thru 12
14	Revenue Requirement				
15	Investment Return and Income Taxes	II (A)	$ 29,906,568	$ 53,359,530	Page 3, Line 26
16	Depreciation Expense	II (B)	8,790,537	14,780,067	Page 5, Line 4
17	Amortization of Loss on Reacquired Debt	II (C)	193,664	325,618	Page 5, Line 5
18	Investment Tax Credit	II (D)	(110,972)	(186,585)	Page 5, Line 6
19	Property Taxes	II (E)	6,483,615	10,901,298	Page 5, Line 8
20	Payroll tax Expense	II (F)	225,027	378,351	Page 5, Line 24
21	Operation & Maintenance Expense	II (G)	4,422,178	7,435,278	Page 5, Line 14
22	Administrative & General Expense	II (H)	3,014,747	5,068,879	Page 5, Line 23
23	Transmission Related Integrated Facilities Charge	II (I)	-	-	
24	Transmission Support Revenue	II (J)	(742,843)	-	Page 7, Line 13
25	Transmission Support Expense	II (K)	3,042,001	-	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)	(108,042)	(181,658)	OATT Schedule 8 TOUT
29	Transmission Rents Received for Electric Property	II (O)	-	-	
30	Total Revenue Requirements		$ 55,116,478	$ 91,880,778	Sum Lines 15 thru 29
31	Total			$ 146,997,256	Sum Line 30, Col C & Col D

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Line	Description	Capitalization 12/31/09	Cost of Capital	Weighted Cost of Capital	Weighted Equity Portion
	Col.A	Col.B	Col.C	Col.D	Col.E
1	Long-Term Debt	$ 1,439,472,003	5.5596%	2.2387%	
2	Preferred Stock	43,000,000	4.5581%	0.0548%	0.0548%
3	Common Equity	2,092,293,592	11.6400%	6.8128%	6.8128%
4	Total Investment Return	$ 3,574,765,595		9.1064%	6.8677%
				ROE per Tariff Sheet No 6032	

Line	Description	Pre-97	Post 96	
5	**Federal Income Tax (FIT)**			
6	A= Preferred & Equity Return	6.86767%	6.86767%	Preferred & Equity Return
7	B= Transmission Related Amortization of ITC	$ (110,972)	$ (186,585)	Page 2, Line 18
8	C= Equity AFUDC Component of Depreciation Expense	$ -	$ -	Equity AFUDC Component of Tramssion Dep Exp
9	D= Transmission Investment Base	$ 221,423,507	$ 372,608,285	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)	3.67099%	3.67101%	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)	0.72915%	0.72915%	State IncomeTax
15	Allowed Return	13.50650%	13.50653%	line 4, Col.D + Line 11 + Line 14
16	D= Transmission Investment Base	$ 221,423,507	$ 372,608,285	Page 2, Line 8
17	**Return**	$ 29,906,568	$ 50,326,444	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		0.58530%	line 19 * line 3 / line 4
21	Additional FIT		0.31516%	Incremental FIT = (a' x FT)/(1-FT)
22	Additional SIT		0.06260%	Incremental SIT = (A' + FIT)(ST)/(1-ST)
23	Additional Return		0.96305%	Sum lines 20 thru 22
24	Post 2003 PTF net Investment		$ 314,945,005	Page 8, line 16
25	Additional Return		$ 3,033,087	Line 23 * Line 24
26	Total Return	$ 29,906,568	$ 53,359,530	Line 17 + Line 25

Line	Description	Capitalization 12/31/09	Cost of Capital	Weighted Cost of Capital	Weighted Equity Portion
27	**Incremental return for PTF 50 Basis Point Adder**				
28	Long-Term Debt	$ 1,439,472,003	5.5596%	2.2387%	
29	Preferred Stock	43,000,000	4.5581%	0.0548%	
30	Common Equity	2,092,293,592	0.5000%	0.2926%	0.2926%
31	Total Investment Return	$ 3,574,765,595		2.5862%	0.2926%

Line	Description	Pre-97	Post 96	
32	**Federal Income Tax (FIT)**			
33	A=	0.29265%	0.29265%	Equity Return
34	B= Transmission Related Amortization of ITC	$ (110,972)	$ (186,585)	Page 2, Line 18
35	C= Equity AFUDC Component of Depreciation Expense	$ -	$ -	Equity AFUDC Component of Tramssion Dep Exp
36	D= Transmission Investment Base	$ 221,423,507	$ 372,608,285	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)	0.13059%	0.13062%	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)	0.02594%	0.02594%	State IncomeTax
42	Allowed Return	0.44918%	0.44921%	line 4, Col.D + Line 11 + Line 14
43	D= Transmission Investment Base	$ 221,423,507	$ 372,608,285	Transmission Investment Base: Page 2, line 13
44	Return	$ 994,590	$ 1,673,783	Line 42 * Line 43
45	Total Incremental Return		$ 5,701,459	

Line	Description	Pre-97	Post 96	
46	Incremental return for Post 2003 PTF Investment			
47	A= Incremental Return	0.5%	0.5%	Incremental return on Equity Component
48	Effective Incremental	0.29265%	0.29265%	Incremental mulitplied by Equity Ratio
49	Additional FIT	0.15758%	0.15758%	Incremental FIT = (a' x FT)/(1-FT)
50	Additional SIT	0.03130%	0.03130%	Incremental SIT = (A' + FIT)(ST)/(1-ST)
51	Additional Return	0.48153%	0.48153%	Lines 22 through 24
52	Post 2003 PTF net Investment	$ 221,423,507	$ 372,608,285	Page 8, Line 15, Col.D
53	Additional Return	$ 1,066,213	$ 1,794,207	Line 51 * Line 52
54	Total 50 Basis Point Incremental Return		$ 2,860,420	Line 19 plus line 26

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Line	Description	Total	Allocation Factors		Transmission Allocated	Pre-97 PTF Allocation Factor (b)	Pre-97 PTF Pre-97 PTF Allocated	Post-96 PTF Allocation Factor (b)	Post-96 PTF 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)	$ 1,222,732,051			$ 1,222,732,051		$ 400,782,972		$ 673,860,892	Page 6, Line 3
3	General Plant	179,657,600	6.5383%	(a)	11,746,539	32.7777%	3,850,241	55.1111%	6,473,645	FF1 207.99g
4	Total Transmission Plant				$ 1,234,478,589		$ 404,633,213		$ 680,334,537	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)	$ (334,077,249)			$ (334,077,249)	32.7777%	$ (109,502,710)	55.1111%	$ (184,113,595)	Page 8, Line 11
8	General Plant Accum.Depreciation	(59,378,446)	6.5383%	(a)	(3,882,336)	32.7777%	(1,272,539)	55.1111%	(2,139,598)	FF1 219.28b
9	Total Transmission Acc Dep				$ (337,959,585)		$ (110,775,249)		$ (186,253,192)	Sum line 7 thru line 8
10	Transmission Accumulated Deferred Taxes									
11	Accumulated Deferred Taxes (282) (d)	$ (534,485,979)	23.6822%	(c)	$ (126,578,121)	32.7777%	$ (41,489,348)	55.1111%	$ (69,758,575)	Line 35
12	Accumulated Deferred Taxes (283) (e)	(570,604,941)	23.6822%	(c)	(135,131,892)	32.7777%	(44,293,074)	55.1111%	(74,472,651)	Line 38
13	Accumulated Deferred Taxes (190)	94,217,253	23.6822%	(c)	22,312,733	32.7777%	7,313,592	55.1111%	12,296,789	FF1 111.82c
14	Total				$ (239,397,280)		$ (78,468,830)		$ (131,934,437)	Sum line 11 thru line 13
15	Transmission loss on Reacquired Debt	$ 23,242,811	23.6822%	(c)	$ 5,504,413	32.7777%	$ 1,804,218	55.1111%	$ 3,033,541	FF1 111.81c
16	Other Regulatory Assets									
17	FAS 106	$ 2,319,775	6.5383%	(a)	$ 151,674					FF1 232.39f
18	FAS 109 Regulatory Asset	35,405,874	23.6822%	(c)	8,384,895					FF1 232.29f
19	FAS 109 Regulatory Liability	(7,234,756)	23.6822%	(c)	(1,713,351)					FF1 278.2f
20	Total	$ 30,490,893			$ 6,823,219	32.7777%	$ 2,236,491	55.1111%	$ 3,760,350	Sum line 17 thru line 19
21	Transmission Prepayments	$ 6,877,218	6.5383%	(a)	$ 449,653	32.7777%	$ 147,386	55.1111%	$ 247,808	FF1 111.57c
22	Transmission Materials and Supplies	$ 1,919,805	100.0000%		$ 1,919,805	32.7777%	$ 629,267	55.1111%	$ 1,058,025	FF1 227.8c + 5c(footnote)
23	Cash Working Capital									
24	Operation & Maintenance Expense						$ 4,422,178		$ 7,435,278	Page 5, line 14
25	Administrative & General Expense						3,014,747		5,068,879	Page 5, line 20
26	Transmission Support Expense						2,299,158		-	Page 7, line 15
27	Total						$ 9,736,083		$ 12,504,157	Sum line 24 thru line 26
28	45 day rule						0.125		0.125	= 45 / 360
29	Cash Working Capital						$ 1,217,010		$ 1,563,020	Line 27 * line 28
30	(a) Labor Allocator Page 6, Line 14	6.5383%								
31	(b) PTF Allocator Page 6, Line 4					32.7777%		55.1111%		
32	(c) Plant Allocator Page 6, Line 20	23.6822%								
33	(d) Account 282	$ 540,039,665	FF1 pg 275, line 9, col k							
34	less amounts related to divestiture	(5,553,686)	FF1 pg 275, line 4, col k							
35	Total Account 282	$ 534,485,979	Sum line 33 thru line 34							
36	(e) Account 283	$ 682,796,457	FF1 pg 277, line 9, col k							
37	less amounts related to divestiture	(112,191,516)	FF1 pg 277, footnote							
38	Total Account 283	$ 570,604,941	Sum line 36 thru line 37							

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Shading denotes an input

Line	Description	Total	Wage/Plant Allocation Factors		Transmission Allocated	Pre-97 PTF Allocation Factor (b)	Pre-97 PTF Allocated	Post 96 PTF 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	$ 26,146,546			$ 26,146,546	32.7777%	$ 8,570,226	55.1111%	$ 14,409,645	Page 8, Line 11, Col.D
3	General Depreciation	10,280,007	6.5383%	(a)	672,137	32.7777%	220,311	55.1111%	370,422	FF1 336.10f
4	Total	$ 36,426,553			$ 26,818,683		$ 8,790,537		$ 14,780,067	Sum line 2 thru line 3
5	Amortization of Loss on Reacquired Debt	$ 2,494,866	23.6822%	(c)	$ 590,840	32.7777%	$ 193,664	55.1111%	$ 325,618	FF1 117.64c
6	Amortization of Investment Tax Credits	$ 1,429,600	23.6822%	(c)	$ 338,561	32.7777%	$ 110,972	55.1111%	$ 186,585	FF1 266.8f & 11f
7	Property Taxes									
8	Transmission Property Taxes	$ 83,525,081	23.6822%	(c)	$ 19,780,590	32.7777%	$ 6,483,615	55.1111%	$ 10,901,298	FF1 263.5i
9	Transmission Operation and Maintenance									
10	Operation and Maintenance	$ 226,729,789			$226,729,789	32.7777%	$ 74,316,723	55.1111%	$ 124,953,245	FF1 321.112b
11	Transmission of Electricity by Others - #565	(191,661,169)			(191,661,169)	32.7777%	(62,822,049)	55.1111%	(105,626,549)	FF1 321.96b
12	Load Dispatching - #561	(11,642,276)			(11,642,276)	32.7777%	(3,816,066)	55.1111%	(6,416,185)	FF1 321.84b-.88b
13	Rents - #567	(9,934,906)			(9,934,906)	32.7777%	(3,256,430)	55.1111%	(5,475,234)	FF1 321.98b
14	O&M for RNS Tariff	$ 13,491,438			$ 13,491,438		$ 4,422,178		$ 7,435,278	Sum line 10 thru line 13
15	Transmission Administrative and General									
16	Administrative and General	$ 121,074,096								FF1 323.197b
17	less Property Insurance (#924)	(585,497)								FF1 323.185b
18	less Regulatory Commission Expenses (#928)	(7,665,807)								FF1 323.189b
19	less General Advertising Expense (#930.1)	(392,760)								FF1 323.191b
20	Subtotal	$ 112,430,032	6.5383%	(a)	$ 7,351,004	32.7777%	$ 2,409,487	55.1111%	$ 4,051,218	Sum line 16 thru line 19
21	Plus Property Ins. alloc. Using Plant Allocator	585,497	23.6822%	(c)	138,659	32.7777%	45,449	55.1111%	76,416	Line 17
22	Plus Regulatory Comm. Exp (Transmission FERC Assessments)	1,707,904	100.0000%	(c)	1,707,904	32.7777%	559,811	55.1111%	941,244	FF1 350.d
23	Total A&G for RNS Tariff	$ 114,723,433			$ 9,197,567		$ 3,014,747		$ 5,068,879	Sum line 20 thru line 22
24	Payroll Tax Expense	$ 10,500,069	6.5383%	(a)	$ 686,525	32.7777%	$ 225,027	55.1111%	$ 378,351	FF1 263.8i
25	(a) Labor Allocator Page 6, Line 14	6.5383%								
26	(b) PTF Allocator Page 6, Line 4					32.7777%		55.1111%		
27	(c) Plant Allocator Page 6, Line 20	23.6822%								

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	$ 400,782,972	$ 673,860,892	$ 443,395,111	Page 8, Col G lines 1,2,3
3	Total Transmission Investment excluding SCADA	$ 1,222,732,051	$ 1,222,732,051	$ 1,222,732,051	Page 8, Line 5, Col.G
4	Percent Allocation	32.7777%	55.1111%	36.2627%	Line 2 / Line 3
5	Total PTF Allocation (Pre 97 + post 96)		87.8887%		Line 4, Col.B plus Col.C
6	**Transmission Wages and Salaries Allocation Factor**				
7	Direct Transmission Wages and Salaries	$ 10,249,802			FF1 354.21b
8	Less EMC Transmission Wages and Salaries	(2,306,393)			Acct 561 Labor
9	Total Transmission Wages and Salaries	$ 7,943,409			Line 7 + Line 8
10	Total Wages and Salaries	$ 158,899,548			FF1 354.28b
11	Administrative and General Wages and Salaries	(37,408,971)			FF1 354.27b
12	Affiliated Company Wages and Salaries less A&G	-			NA
13	Total Wages and Salaries net of A&G (line 7 - 8 + 9)	$ 121,490,577			Sum lines 10 thru 12
14	Percent Allocation	6.5383%			Line 9 / Line 13
15	**Plant Allocation Factor**				
16	Total Transmission Investment (exc SCADA)	$ 1,222,732,051			Line 2
17	Plus Transmission Related General Plant (Line 2 Wkst.3)	11,746,539			FF1 3, line 2, Col.D
18	Revised Numerator (Line 12 + Line 13)	$ 1,234,478,589			Line 16 + Line 17
19	Total Plant in Service	$ 5,212,682,028			FF1 207.104g
20	Percent Allocation	23.6822%			Line 18 / Line 19
21	Transmission Plant only Allocator	23.4569%			Line 16 / Line 19

ISO New England Inc.
FERC Electric Tariff No. 3
Open Access Transmission Tariff
Section II - Attachment F Implementation Rule
per Tariff Attachment F and NEPOOL Agreement Part 2, Section 6.3
NSTAR Electric Company
Page 7

Line	PTF Supporting Facilities	Revenues	Expenses	Reference
	Col.B	Col.C	Col.D	
1	National Grid Support Revenues	$ 4,644		FF1 p.300 line 22 col.(b) footnote
2	Hydro Quebec Phase 2 Support	430,015		FF1 p.300 line 22 col.(b) footnote
3	EUA/NEP Station 342 Support	68,040		FF1 p.300 line 22 col.(b) footnote
4	Montaup Station 451 Support	19,112		FF1 p.300 line 22 col.(b) footnote
5	NEP Line 201-502 Medway Support	8,034		FF1 p.300 line 22 col.(b) footnote
6	Reading Lines 211-503/504 Support	165,958		FF1 p.300 line 22 col.(b) footnote
7	Trans Support Miles Standish - Bridgewater	47,040		FF1 p.300 line 22 col.(b) footnote
8	New England Power Co		103,093	FF1 p.332 line 1 col.(h)
9	Wellesley Municipal Lgt		16,560	FF1 p.332 line 3 col.(h)
10	New England Power Support		1,568,331	FF1 p.321 line 98 col.(b) footnote
11	Hydro Quebec Phase II NEP AC, Chester SVC		1,351,077	FF1 p.321 line 98 col.(b) footnote
12	Transmission Line Rents		2,940	FF1 p.321 line 98 col.(b) footnote
13	Total	$ 742,843	$ 3,042,001	
14	Net		$ 2,299,158	

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

Transmission Investment

Line	Description	12/31/08	Additions	Retirements	Reclass	Adjustment	12/31/2009
	Col.A	Col.B	Col.C	Col.D	Col.E	Col.F	Col.G
1	Pre-97 PTF(excl. SCADA)	$ 403,559,573	$ -	$ (2,049,363)	$ (727,237)	$ -	$ 400,782,972
2	Post-96 PTF not in plan (excl. SCADA)	213,850,515	18,554,212	(1,938,947)	-	-	230,465,781
3	Post-03 PTF in plan (excl. SCADA)	353,615,347	89,743,190	(4,333)	40,908	-	443,395,111
4	Non-PTF(excl. SCADA)	136,986,947	11,021,296	(580,882)	660,826	-	148,088,186
5	Sub -Total	$ 1,108,012,382	$ 119,318,698	$ (4,573,526)	$ (25,503)	$ -	$ 1,222,732,051
6	SCADA (Billed under Schedule 1)						
7	PTF	$ 9,680,493	$ -	$ (353,425)	$ -	$ -	$ 9,327,068
8	Non-PTF	1,943,683	-	-	-	-	1,943,683
9	Sub - Total	$ 11,624,176	$ -	$ (353,425)	$ -	$ -	$ 11,270,751
10	Total Transmission	$ 1,119,636,558	$ 119,318,698	$ (4,926,951)	$ (25,503)	$ -	$ 1,234,002,802
		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	$ 337,491,052	$ 3,413,803	$ 334,077,249	FERC Form 1 page 219, line 25, col b
12	Depreciation Expense	$ 26,422,121	$ 275,575	$ 26,146,546	FERC Form 1 page 336, line 7, col b

Line	Description	Actual Per Books	
13	Post-03 PTF in Plan subject to 100 bp adder	$ 360,773,429	
14	Transmission Accum. Depreciation subject to 100 bp adder	(26,054,768)	
15	Transmission Accumulated Deferred Taxes subject to 100 bp adder	(19,773,656)	
16	Net Post-03 PTF in Plan subject to 100 bp adder	$ 314,945,005	Sum lines 13 thru 15

17 (a) Values for SCADA taken from Schedule 1 Revenue Requirement

Reading Municipal Light Plant

Sheet: Input Panel — Input Panel

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

Shading denotes an input

Submitted on:	05/21/2010
Revenue Requirements for (year):	2009
Customer:	Reading Municipal Light Plant
Customer's NABs Number:	
Name of Participant responsible for customer's billing:	Bill Seldon
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	=	1,058	(a)	203,319	(f)
Total of Attachment F - Section J - Support Revenue		0	(b)	0	(g)
Total of Attachment F - Section K - Support Expense		105,791	(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)		106,849	(e)=(a)-(b)+(c)+(d)	203,319	(j)=(f)-(g)+(h)+(i)
Forecasted Incremental Transmission Revenue Requirements				0	(m)
Annual True-up		(34,003)		2,682	(n)
Interest Charge on Annual True-up		(1,670)		132	(o)
Total = (e) + (j) + (k) + (l) + (m) + (n) + (o)		71,176	(p)	206,133	(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:				277,309	(r) = (p)+(q)

Reading Municipal Light Plant

RNS Rate

Annual Revenue Requirements of pre-1997 & post-1996 PTF
for costs in 2008 06/09-05/10

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	Pre 1997	Post 1996	Reference
1	Transmission Plant	I (A)(1)(a)	0	2,476,271	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	2,476,271	
5	Accumulated Depreciation	I (A)(1)(d)	0	949,789	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	1,626,482	
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)	17,432	1,010	Worksheet 3, line 24 column 5
13	Total Investment Base (Line 9+11+12+13)		17,432	1,627,492	
	II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	I (A)	1,395	130,199	Worksheet 2
15	Depreciation Expense	I (B)	0	15,602	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	46,758	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	1,032	Worksheet 4, line 13 column 5
21	Administrative & General Expense	I (H)	0	7,046	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)	139,457	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)		140,852	200,637	

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	2,476,271
34	Post-96 Carrying Charge Factor (Post-96 CCF)	7.8%
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 2009

1	2009 Actual Annual RR			106,849	203,319	
2	2009 Est. Transmission Revenue Requirements (as billed)	6/09-05/10	Appendix C	140,852	200,637	ATRR - Prior Year
3	True-up (Over)/Under (Line 1 - Line 2)			-34,003	2,682	

	(Overcollection)/Undercollection
Pre'97	($34,003)
Post'96	$2,682

Initial Billing Period	Pre 1997 Balance	Post 1996 Balance	FERC Monthly Interest Rate	Pre 1997 Interest	Post 1996 Interest
June 2007	($34,003)	$2,682	0.56%	($190)	$15
July 2007	(34,193)	2,697	0.45%	-154	$12
August 2007	(34,193)	2,697	0.45%	-154	$12
September 2007	(34,193)	2,697	0.44%	-150	$12
October 2007	(34,652)	2,733	0.42%	-146	$11
November 2007	(34,652)	2,733	0.41%	-142	$11
December 2007	(34,652)	2,733	0.42%	-146	$11
January 2008	(35,085)	2,767	0.38%	-133	$11
February 2008	(35,085)	2,767	0.34%	-119	$9
March 2008	(35,085)	2,767	0.38%	-133	$11
April 2008	(35,471)	2,798	0.28%	-99	$8
May 2008	(35,471)	2,798	0.29%	-103	$8
		Total Interest		-$1,670	$132
		True-Up		-$34,003	$2,682
		Total TU & Int		**-$35,673**	**$2,814**

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:	18-May-09
Revenue Requirements for (year):	Calendar Year 2009
Customer:	Reading Municipal Light Department
Customer's NABs Number:	
Name of Participant responsible for customer's billing:	Bill Seldon
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	=	1,058	(a)		(f)
Total of Attachment F - Section J - Support Revenue		0	(b)	0	(g)
Total of Attachment F - Section K - Support Expense		105,791	(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)		106,849	(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:	106,849	(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)	106,849	(l)=(k)+(b)+(g)-(h)

Calendar Year 2009

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)	13,224	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		13,224	

Line No.	II. REVENUE REQUIREMENTS	Attachment F Reference Section:	Reading	Reference
14	Investment Return and Income Taxes	(A)	1,058	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)	105,791	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)		106,849	

Sheet: Worksheet 2a

Reading Municipal Light Department
Annual Revenue Requirements
Calendar Year 2009

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) / 13,224) 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) / 13,224) + 0.0000000)* 0 / (1 - 0)

= 0.0000000

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

		(PTF)	
INVESTMENT BASE	$	13,224	From Worksheet 1
x Cost of Capital Rate		0.0800000	
= Investment Return and Income Taxes		1,058	To Worksheet 1

Sheet: Worksheet 3a

Reading Municipal Light Department

Calendar Year 2009

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	$ 21,610,018	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	2,247,392		2,247,392	0.0000%	0	Page 8A, line 31(g) less Page 16, line 31(g)
6	General Plant Accum.Depreciation	15,192,196	0.0000% (a)	0	0.0000%	0	Page 8B, line 29(g) less Page 17, line 29(g)
7	Total (line 5+6)			2,247,392		0	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	0	6.8302% (c)	0	0.0000%	0	None known
9	Accumulated Deferred Taxes (190)	0	6.8302% (c)	0	0.0000%	0	None known
10	Total (line 8+9)			0		0	
11	Transmission loss on Reacquired Debt	0	6.8302% (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	6.8302% (c)	0	0.0000%	0	None known
14	Other Regulatory Liabilities (254.DK)	0	6.8302% (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					105,791	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					105,791	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					13,224	

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

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	3,001		3,001	0.0000%	0	Page 16, line 31(d)
2	General Depreciation	846,079	0.0000% (a)	0	0.0000%	0	Page 17, line 29(d)
3	Total (line 1+2)			3,001		0	
4	Amortization of Loss on Reacquired Debt	0	6.8302% (c)	0	0.0000%	0	None known
5	Amortization of Investment Tax Credits	0	6.8302% (c)	0	0.0000%	0	None known
	Property Taxes *						
6	Transmission Property Taxes	2,149,697	6.8302%	146,829	0.0000%	0	DTE, p. 21 line 24
7	General Property Taxes	2,149,697	0.0000% (a)	0	0.0000%	0	DTE, p. 21 line 24
8	Total (line 6+7)			146,829		0	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	6,975,317		6,975,317	0	0	Page 40, line 50(b)
10	Transmission of Electricity by Others - #565	6,972,592		6,972,592	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	4,376,816					Page 42, line 6(b)
15	*less Property Insurance (#924)*	*374,797*					Page 41, line 47(b)
16	*less Regulatory Commission Expenses (#928)*	*0*					Page 41, line 50(b)
17	*less General Advertising Expense (#930.1)*	*149,128*					*assumed none*
18	Subtotal [line 14 minus (15 thru 17)]	3,852,891	0.0000% (a)	0	0.0000%	0	
19	*PLUS Property Insurance alloc. using Plant Allocatior*	*374,797*	*6.8302% (c)*	25,599	0.0000%	0	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	*0*	*6.8302% (c)*	0	0.0000%	0	
21	*PLUS Trans. Related General Advertising Expense*	*0*	*6.8302% (c)*	0	0.0000%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*4,227,688*		*25,599*		*0*	
23	*Payroll Tax Expense*	67,654	*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 2009

Line No.		Reading	Mass DTE AR Reference
	PTF Transmission Plant Allocation Factor		
1	PTF Transmission Investment	0	See Worksheet
2	Total Transmission Investment	7,917,558	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	6,884,785	Page 42, line 24 (c)
8	Administrative and General Wages and Salaries	789,863	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)	6,094,922	
11	Percent Allocation (Line 6/Line 10)	0.0000%	
	Plant Allocation Factor		
12	Total Transmission Investment	7,917,558	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)*	7,917,558	
15	Total Plant in Service	115,920,210	Page 8B, line 30 (g)
16	Percent Allocation (Line 14 / Line 15)	6.8302%	

Sheet: Worksheet 6

Affiliated Company Wages and Salaries

Calendar Year 2009

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

Sheet: Worksheet 7

Calendar Year 2009

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]		2,032
	345 kV "stabilizer" 342 line			
	345 kV Walpole - Medway 325 line			
	345 kV Carver - Walpole 331 line			
	345 kV Jordan Rd - Canal 342 line			
CEC	Second Canal line			
	345 kV Pilgrim-Bridgewater - 355 line			
	345 kV Myles Standish - Canal 342 line			
CMP	**345 kV Buxton-South Gorham 386 line**			
	115 kV Wyman 164-167 lines			
	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**			14,477
	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]		31,239
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 394 line	332(g)		2,688
	115 kV Read - Washington V148 line			
NU	**345 kV 363, 369 and 394 Seabrook lines**			14,137
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310 line	330.1(n)		2,294
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
	Seabrook			38,924
		Total =	0	105,791

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:	21-May-09
Revenue Requirements for (year):	Calendar Year 2009
Customer:	Reading Municipal Light Department
Customer's NABs Number:	
Name of Participant responsible for customer's billing:	Bill Seldon
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	=		(a)	203,319	(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)	203,319	(j)

Annual Revenue Requirement Total = Sum of Pre-97 Revenue Requirements and Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:	203,319	(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)	203,319	(l)=(k)+(b)+(g)-(h)

Calendar Year 2009

Shading denotes an input

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	Reading	Reference
1	Transmission Plant	(A)(1)(a)	2,546,936	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)		2,546,936	
5	Accumulated Depreciation	(A)(1)(d)	722,946	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	0	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	0	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	0	Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		1,823,990	
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)	1,139	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		1,825,129	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	146,010	Worksheet 2
15	Depreciation Expense	(B)	965	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	(C)	0	Worksheet 4, line 4 column 5
17	Investment Tax Credit	(D)	0	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	47,232	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	0	*Worksheet 4, line 17 column 5*
20	Operation & Maintenance Expense	(G)	877	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	8,235	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)		203,319	

Reading Municipal Light Department

Annual Revenue Requirements

Calendar Year 2009

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) / 1,825,129) 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) / 1,825,129) + 0.0000000)* 0
(1 - 0)

= 0.0000000

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

	(PTF)	
INVESTMENT BASE	$ 1,825,129	From Worksheet 1
x Cost of Capital Rate	0.0800000	
= Investment Return and Income Taxes	146,010	To Worksheet 1

Sheet: Worksheet 3a

Reading Municipal Light Department
Calendar Year 2009

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	$ 2,546,936		2,546,936		2,546,936	Line 1, Worksheet 5
2	General Plant	$ 21,610,018	0.0000% (a)	0	32.1682%	0	Page 8B line 29(g)
3	Total (line 1+2)			2,546,936		2,546,936	
4	Transmission Plant Held for Future Use	0		0	32.1682%	0	None known
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	2,247,392		2,247,392	32.1682%	722,946	Page 8A, line 31(g) less Page 16, line 31(g)
6	General Plant Accum.Depreciation	15,192,196	0.0000% (a)	0	32.1682%	0	Page 8B, line 29(g) less Page 17, line 29(g)
7	Total (line 5+6)			2,247,392		722,946	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	0	6.8302% (c)	0	32.1682%	0	None known
9	Accumulated Deferred Taxes (190)	0	6.8302% (c)	0	32.1682%	0	None known
10	Total (line 8+9)			0		0	
11	Transmission loss on Reacquired Debt	0	6.8302% (c)	0	32.1682%	0	None known
	Other Regulatory Assets						
12	FAS 106	0	0.0000% (a)	0	32.1682%	0	None known
13	FAS 109	0	6.8302% (c)	0	32.1682%	0	None known
14	Other Regulatory Liabilities (254.DK)	0	6.8302% (c)	0	32.1682%	0	
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments	0	0.0000% (a)	0	32.1682%	0	Assumed none
17	Transmission Materials and Supplies	0	0.0000%	0	32.1682%	0	Assumed none
18	Cash Working Capital						
19	Operation & Maintenance Expense					877	Worksheet 1, Line 20
20	Administrative & General Expense					8,235	Worksheet 1, Line 21
21	Transmission Support Expense					0	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					9,112	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					1,139	

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

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	3,001		3,001	32.1682%	965	Page 16, line 31(d)
2	General Depreciation	846,079	0.0000% (a)	0	32.1682%	0	Page 17, line 29(d)
3	Total (line 1+2)			3,001		965	
4	Amortization of Loss on Reacquired Debt	0	6.8302% (c)	0	32.1682%	0	None known
5	Amortization of Investment Tax Credits	0	6.8302% (c)	0	32.1682%	0	None known
	Property Taxes *						
6	Transmission Property Taxes	2,149,697	6.8302%	146,829	32.1682%	47,232	DTE, p. 21 line 24
7	General Property Taxes	2,149,697	0.0000% (a)	0	32.1682%	0	DTE, p. 21 line 24
8	Total (line 6+7)			146,829		47,232	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	6,975,317		6,975,317	0.321682	2,243,834	Page 40, line 50(b)
10	Transmission of Electricity by Others - #565	6,972,592		6,972,592	0.321682	2,242,957	Page 40, line 38(b)
11	Load Dispatching - #561	0		0	0.321682	0	Page 40, line 34(b)
12	**Station Expenses & Rents - #562 / #567	0		0	0.321682	0	Page 40, line 35(b) 40(b)
13	O&M less lines 10, 11 & 12	2,725		2,725	32.1682%	877	
	Transmission Administrative and General						
14	Administrative and General	4,376,816					Page 42, line 6(b)
15	*less Property Insurance (#924)*	*374,797*					Page 41, line 47(b)
16	*less Regulatory Commission Expenses (#928)*	*0*					Page 41, line 50(b)
17	*less General Advertising Expense (#930.1)*	*149,128*					*assumed none*
18	Subtotal [line 14 minus (15 thru 17)]	3,852,891	0.0000% (a)	0	32.1682%	0	
19	*PLUS Property Insurance alloc. using Plant Allocation*	*374,797*	*6.8302% (c)*	25,599	32.1682%	8,235	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	*0*	*6.8302% (c)*	0	32.1682%	0	
21	*PLUS Trans. Related General Advertising Expense*	*0*	*6.8302% (c)*	0	32.1682%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*4,227,688*		*25,599*		*8,235*	
23	*Payroll Tax Expense*	67,654	*0.0000% (a)*	*0*	*32.1682%*	*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

Calendar Year 2009

Shading denotes an input

Line No.			Mass DTE AR Reference
	PTF Transmission Plant Allocation Factor	**Reading**	
1	PTF Transmission Investment	2,546,936	See Worksheet
2	Total Transmission Investment	7,917,558	Page 8A, line 31(g)
3	Percent Allocation (Line 1/Line 2)	32.1682%	
	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	6,884,785	Page 42, line 24 (c)
8	Administrative and General Wages and Salaries	789,863	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)	6,094,922	
11	Percent Allocation (Line 6/Line 10)	0.0000%	
	Plant Allocation Factor		
12	Total Transmission Investment	7,917,558	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)*	7,917,558	
15	Total Plant in Service	115,920,210	Page 8B, line 30 (g)
16	Percent Allocation (Line 14 / Line 15)	6.8302%	

Sheet: Worksheet 6

Affiliated Company Wages and Salaries

Calendar Year 2009

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

Sheet: Worksheet 7

Calendar Year 2009

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)		0
	115 kV Read - Washington V148 line			
NU	**345 kV 363, 369 and 394 Seabrook lines**			0
	Fairmont 115 kV Substation	330.1(n);[330 for HWP]		
	345 kV Millstone-Manchester 310 line	330.1(n)		0
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
	Seabrook			0
		Total =	0	0

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

Taunton Municipal Light Plant

Sheet: Input Panel | Input Panel

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

Shading denotes an input

Submitted on:	05/26/2009
Revenue Requirements for (year):	2009
Customer:	Taunton Municipal Light Plant
Customer's NABs Number:	
Name of Participant responsible for customer's billing:	Michael Horrigan
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	=	86,982	(a)	0	(f)
Total of Attachment F - Section J - Support Revenue		0	(b)	0	(g)
Total of Attachment F - Section K - Support Expense		197,545	(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)		284,527	(e)=(a)-(b)+(c)+(d)	0	(j)=(f)-(g)+(h)+(i)
Forecasted Incremental Transmission Revenue Requirements				0	(m)
Annual True-up		(58,972)		0	(n)
Interest Charge on Annual True-up		(2,896)		-	(o)
Total = (e) + (j) + (k) + (l) + (m) + (n) + (o)		222,659	(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: 222,659 (r) = (p)+(q)

Taunton Municipal Light Plant

Annual Revenue Requirements of pre-1997 & post-1996 PTF
for costs in 2008 06/09-05/10

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	Pre 1997	Post 1996	Reference
1	Transmission Plant	I (A)(1)(a)	1,500,243	0	Worksheet 3, line 1 column 5
2	General Plant	I (A)(1)(b)	2,218	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)		1,502,461	0	
5	Accumulated Depreciation	I (A)(1)(d)	1,322,380	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)		180,081	0	
10	Prepayments	I (A)(1)(h)	106	0	Worksheet 3, line 16 column 5
11	Materials & Supplies	I (A)(1)(i)	21,535	0	Worksheet 3, line 17 column 5
12	Cash Working Capital	I (A)(1)(j)	34,284	0	Worksheet 3, line 24 column 5
13	Total Investment Base (Line 9+11+12+13)		236,006	0	
	II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	I (A)	18,880	0	Worksheet 2
15	Depreciation Expense	I (B)	25,405	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)	24,702	0	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	I (F)	241	0	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	I (G)	53,380	0	Worksheet 4, line 13 column 5
21	Administrative & General Expense	I (H)	4,435	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)	216,456	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)		343,499	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 2009

1	2009 Actual Annual RR			284,527	0	Input Panel Subtotals
2	2009 Est. Transmission Revenue Requirements (as billed)	6/09-05/10	Appendix C	343,499	0	ATRR - Prior Year
3	True-up (Over)/Under (Line 1 - Line 2)			-58,972	0	

	(Overcollection)/Undercollection
Pre'97	($58,972)
Post'96	$0

Initial Billing Period	Pre 1997 Balance	Post 1996 Balance	FERC Monthly Interest Rate	Pre 1997 Interest	Post 1996 Interest
June 2007	($58,972)	$0	0.56%	($330)	$0
July 2007	(59,302)	0	0.45%	-267	$0
August 2007	(59,302)	0	0.45%	-267	$0
September 2007	(59,302)	0	0.44%	-261	$0
October 2007	(60,097)	0	0.42%	-252	$0
November 2007	(60,097)	0	0.41%	-246	$0
December 2007	(60,097)	0	0.42%	-252	$0
January 2008	(60,848)	0	0.38%	-231	$0
February 2008	(60,848)	0	0.34%	-207	$0
March 2008	(60,848)	0	0.38%	-231	$0
April 2008	(61,517)	0	0.28%	-172	$0
May 2008	(61,517)	0	0.29%	-178	$0
		Total Interest		-$2,896	$0
		True-Up		-$58,972	$0
		Total TU & Int		**-$61,868**	**$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-09
Revenue Requirements for (year):	Calendar Year 2009
Customer:	Taunton Municipal Lighting Plant
Customer's NABs Number:	
Name of Participant responsible for customer's billing:	Michael Horrigan
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	=	86,982	(a)	0	(f)
Total of Attachment F - Section J - Support Revenue		0	(b)	0	(g)
Total of Attachment F - Section K - Support Expense		197,545	(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)		284,527	(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:		284,527	(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)	284,527	(l)=(k)+(b)+(g)-(h)

Calendar Year 2009

Shading denotes an input

Line No.	I. INVESTMENT BASE	Attachment F Reference Section:	Taunton	Reference
1	Transmission Plant	(A)(1)(a)	1,500,243	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	1,512	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)		1,501,755	
5	Accumulated Depreciation	(A)(1)(d)	1,343,496	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)		158,259	
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)	27,421	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		185,680	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	14,854	Worksheet 2
15	Depreciation Expense	(B)	26,874	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)	23,302	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	132	*Worksheet 4, line 17 column 5*
20	Operation & Maintenance Expense	(G)	17,621	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	4,199	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)	197,545	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)		284,527	
			86,982	

Taunton Municipal Lighting Plant
Annual Revenue Requirements
Calendar Year 2009

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 = (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) / 185,680) 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) / 185,680) + 0.0000000)* 0
(1 - 0)

= 0.0000000

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

		(PTF)	
INVESTMENT BASE	$	185,680	From Worksheet 1
x Cost of Capital Rate		0.0800000	
= Investment Return and Income Taxes		14,854	To Worksheet 1

Sheet: Worksheet 3a

Taunton Municipal Lighting Plant
Calendar Year 2009

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	30,213,007	0.0243% (a)	7,342	20.5970%	1,512	Page 8B line 29(g)
3	Total (line 1+2)			7,291,136		1,501,755	
4	Transmission Plant Held for Future Use	0		0	20.5970%	0	None known
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	6,520,227		6,520,227	20.5970%	1,342,971	Page 8A, line 31(g) less Page 16, line 31(g)
6	General Plant Accum.Depreciation	10,483,984	0.0243% (a)	2,548	20.5970%	525	Page 8B, line 29(g) less Page 17, line 29(g)
7	Total (line 5+6)			6,522,775		1,343,496	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	0	3.8768% (c)	0	20.5970%	0	None known
9	Accumulated Deferred Taxes (190)	0	3.8768% (c)	0	20.5970%	0	None known
10	Total (line 8+9)			0		0	
11	Transmission loss on Reacquired Debt	0	3.8768% (c)	0	20.5970%	0	None known
	Other Regulatory Assets						
12	FAS 106	0	0.0243% (a)	0	20.5970%	0	None known
13	FAS 109	0	3.8768% (c)	0	20.5970%	0	None known
14	Other Regulatory Liabilities (254.DK)	0	3.8768% (c)	0	20.5970%	0	
15	Total (line 12+13+14)			0		0	
16	Transmission Prepayments	0.00	0.0243% (a)	0	20.5970%	0	
17	Transmission Materials and Supplies	0.00	3.8768%	0	20.5970%	0	
18	Cash Working Capital						
19	Operation & Maintenance Expense					17,621	Worksheet 1, Line 20
20	Administrative & General Expense					4,199	Worksheet 1, Line 21
21	Transmission Support Expense					197,545	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					219,365	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					27,421	

(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 2009

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	129,873		129,873	20.5970%	26,750	Page 16, line 31(d)
2	General Depreciation	2,483,070	0.0243% (a)	603	20.5970%	124	Page 17, line 29(d)
3	Total (line 1+2)			130,476		26,874	
4	Amortization of Loss on Reacquired Debt	0	3.8768% (c)	0	20.5970%	0	None known
5	Amortization of Investment Tax Credits	0	3.8768% (c)	0	20.5970%	0	None known
	Property Taxes *						
6	Transmission Property Taxes	2,900,000	0.038768	112,427	20.5970%	23,157	
7	General Property Taxes	2,900,000	0.0243% (a)	705	20.5970%	145	
8	Total (line 6+7)			113,132		23,302	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	5,256,172		5,256,172	0.20597	1,082,614	Page 40, line 49(b)
10	Transmission of Electricity by Others - #565	5,144,367		5,144,367	0.20597	1,059,585	Page 40, line 38(b)
11	Load Dispatching - #561	11,303		11,303	0.20597	2,328	Page 40, line 34(b)
12	**Station Expenses & Rents - #562 / #567	14,954		14,954	0.20597	3,080	Page 40, line 35(b) 40(b)
13	O&M less lines 10, 11 & 12	85,548		85,548	20.5970%	17,621	
	Transmission Administrative and General						
14	Administrative and General	5,123,155					Page 42, line 5(b)
15	*less Property Insurance (#924)*	498,053					Page 41, line 47(b)
16	*less Regulatory Commission Expenses (#928)*	0					Page 41, line 50(b)
17	*less General Advertising Expense (#930.1)*	196,638					*930.1*
18	Subtotal [line 14 minus (15 thru 17)]	4,428,464	0.0243% (a)	1,076	20.5970%	222	
19	*PLUS Property Insurance alloc. using Plant Allocation*	*498,053*	*3.8768% (c)*	19,309	20.5970%	3,977	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	*0*	*3.8768% (c)*	0	20.5970%	0	assumed none
21	*PLUS Trans. Related General Advertising Expense*	*0*	*3.8768% (c)*	0	20.5970%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*4,926,517*		*20,385*		*4,199*	
23	*Payroll Tax Expense*	*2,642,972*	*0.0243% (a)*	*642*	*20.5970%*	*132*	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	1,791,741	|Combined
Medicare	150,025	
CT Unemployment		
MA Unemployment	701,206	
MA Universal Health		
VT Unemployment		
NH Unemployment		
Total	2,642,972	*To Line 23*

Sheet: Worksheet 5

Calendar Year 2009

Shading denotes an input

Line No.		Taunton	Mass DTE AR Reference
	PTF Transmission Plant Allocation Factor		
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	3,168	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)	3,168	
7	Total Wages and Salaries	14,730,966	Page 42, line 24©
8	Administrative and General Wages and Salaries	1,693,203	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)	13,037,763	
11	Percent Allocation (Line 6/Line 10)	0.0243%	
	Plant Allocation Factor		
12	Total Transmission Investment	7,283,794	Line 2
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	7,342	*Worksheet 3, Line 2*
14	*= Revised Numerator (Line 12 + Line 13)*	7,291,136	
15	Total Plant in Service	188,073,066	Page 8B, line 29(g)
16	Percent Allocation (Line 14 / Line 15)	3.8768%	

Sheet: Worksheet 6

Affiliated Company Wages and Salaries

Shading denotes an input — Calendar Year 2009

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

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			
				73,388
				92,014
	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]		21,671
	345 kV Golden Hills-Mystic 349 line			
	345 kV NH/MA border-Tewksbury 394 line	332(g)		7,640
	115 kV Read - Washington V148 line			
NU	**345 kV 363, 369 and 394 Seabrook lines**			2,832
	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	197,545

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:	7/23/2010
Revenue Requirements for (year):	2010
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	=	22,220,002	(a)	73,798,957	(f)
Total of Attachment F - Section J - Support Revenue		0	(b)	0	(g)
Total of Attachment F - Section K - Support Expense		827,492	(c)	0	(h)
Total of Attachment F - Section L through O		(88,171)	(d)	0	(i)
Sub Total - Sum (A through I) - J + K + (L through O)		22,959,323	(e)=(a)-(b)+(c)+(d)	73,798,957	(j)=(f)-(g)+(h)+(i)
Forecasted Incremental Transmission Revenue Requirements		0	n/a	3,320,051	(m)
Annual True-up		4,738,003	(k)	13,411,424	(n)
Interest Charge on Annual True-up		158,374	(l)	448,296	(o)
Total = (e) + (j) + (k) + (l) + (m) + (n) + (o)		27,855,701	(p)	90,978,727	(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:				118,834,428	(r) = (p)+(q)

The United Illuminating Company
Annual Revenue Requirements of pre-1997 PTF
for costs in 2009

RNS Rate

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)	110,228,207	Worksheet 3, line 1 column 5
2	General Plant	I (A)(1)(b)	2,351,015	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	I (A)(1)(c)	6,230,425	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		118,809,647	
5	Accumulated Depreciation	I (A)(1)(d)	16,715,343	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	I (A)(1)(e)	13,693,285	Worksheet 3, line 10 column 5
7	Loss On Reacquired Debt	I (A)(1)(f)	1,022,638	Worksheet 3, line 11 column 5
8	Other Regulatory Assets	I (A)(1)(g)	7,039,173	Worksheet 3, line 15 column 5
9	Net Investment (Line 4-5-6+7+8)		96,462,830	
10	Prepayments	I (A)(1)(h)	94,751	Worksheet 3, line 16 column 5
11	Materials & Supplies	I (A)(1)(i)	48,088	Worksheet 3, line 17 column 5
12	Cash Working Capital	I (A)(1)(j)	749,890	Worksheet 3, line 24 column 5
13	Total Investment Base (Line 9+11+12+13)		97,355,559	
	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	I (A)	12,765,855	Worksheet 2
15	Depreciation Expense	I (B)	2,663,093	Worksheet 4, line 3 column 5
16	Amortization of Loss on Reacquired Debt	I (C)	86,730	Worksheet 4, line 4 column 5
17	Investment Tax Credit	I (D)	(12,139)	Worksheet 4, line 5 column 5
18	Property Taxes	I (E)	1,404,201	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	I (F)	140,636	Worksheet 4, line 23 column 5
20	Operation & Maintenance Expense	I (G)	2,429,509	Worksheet 4, line 13 column 5
21	Administrative & General Expense	I (H)	2,742,117	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)	827,492	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)	(15,343)	Txm related Acct 456
28	Transmission Rents Received from Electric Property	I (O)	(72,828)	Txm related Acct 454-rent
29	Total Revenue Requirements (Line 14 thru 28)		22,959,323	

The United Illuminating Company
Annual Revenue Requirements of post-1996 PTF
for costs in 2009

Sheet: Worksheet 1a

Shading denotes an input

Line No.		Attachment F Reference	UI	Reference
	I. INVESTMENT BASE	*Section:*		
1	Transmission Plant	I (A)(1)(a)	349,117,069	Worksheet 3a, line 1 column 5
2	General Plant	I (A)(1)(b)	7,446,185	Worksheet 3a, line 2 column 5
3	Plant Held For Future Use	I (A)(1)(c)	19,733,133	Worksheet 3a, line 4 column 5
4	Total Plant (Lines 1+2+3)		376,296,387	
5	Accumulated Depreciation	I (A)(1)(d)	52,941,184	Worksheet 3a, line 7 column 5
6	Accumulated Deferred Income Taxes	I (A)(1)(e)	43,369,658	Worksheet 3a, line 10 column 5
7	Loss On Reacquired Debt	I (A)(1)(f)	3,238,922	Worksheet 3a, line 11 column 5
8	Other Regulatory Assets	I (A)(1)(g)	22,294,617	Worksheet 3a, line 15 column 5
9	Net Investment (Line 4-5-6+7+8)		305,519,084	
10	Prepayments	I (A)(1)(h)	300,099	Worksheet 3a, line 16 column 5
11	Materials & Supplies	I (A)(1)(i)	152,305	Worksheet 3a, line 17 column 5
12	Cash Working Capital	I (A)(1)(j)	2,047,460	Worksheet 3a, line 24 column 5
13	Total Investment Base (Line 9+11+12+13)		308,018,948	
	II. PRIOR CALENDAR YEAR ACTUAL REVENUE REQUIREMENT			
14	Investment Return and Income Taxes	I (A)	40,389,508	Worksheet 2a
15	Depreciation Expense	I (B)	8,434,602	Worksheet 4a, line 3 column 5
16	Amortization of Loss on Reacquired Debt	I (C)	274,693	Worksheet 4a, line 4 column 5
17	Investment Tax Credit	I (D)	(38,446)	Worksheet 4a, line 5 column 5
18	Property Taxes	I (E)	4,447,416	Worksheet 4a, line 8 column 5
19	Payroll Tax Expense	I (F)	445,427	Worksheet 4a, line 23 column 5
20	Operation & Maintenance Expense	I (G)	7,694,792	Worksheet 4a, line 13 column 5
21	Administrative & General Expense	I (H)	8,684,890	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 Tai	I (N)	0	
28	Transmission Rents Received from Electric Propert	I (O)	0	
29	Total Revenue Requirements (Line 14 thru 28)		70,332,882	0.201459305

	III. CURRENT CALENDAR YEAR ESTIMATED INCREMENTAL REVENUE REQUIREMENT		
30	Carrying Charge Factor Base Revenue Requirement Numerator	70,332,882	Sum of Lines 14 through 21
31	Post-2003 Enhanced Return Addition to Revenue Requirement	3,466,075	Worksheet 1b Line 6 Column 2 and L
32	Total Post-96 PTF Revenue Requirement	73,798,957	Line 30 + Line 31
33	Post-96 PTF Transmission Plant in Service	349,117,069	Line 1
34	Post-96 Carrying Charge Factor (Post-96 CCF)	0.211387421	Line 32 / Line 33
35	Forecasted Post-96 PTF Plant Additions	15,706,000	Worksheet WinBEAMS Report
36	Forecasted Post-96 Localized PTF Plant Additions	0	Worksheet Used Life Credit Exibit
37	Forecasted Post-96 Pool-Supported PTF Plant Additions	15,706,000	Line 35 - Line 36
38	Post-96 Estimated Incremental Revenue Requirement	3,320,051	Line 34 * Line 37

The United Illuminating Company
Annual Revenue Requirements of post-2003 PTF Incremental Return
for costs in 2009

Line No.		(1) Total Transmission	(2) Post-2003 [1] PTF	(3) Post-2003 [2] PTF	Total Transmission Reference
I.	INVESTMENT BASE				
1	Transmission Plant	476,798,581	**334,315,008**	**178,342,942**	Internal Plant Accounting
2	Accumulated Depreciation	69,243,722	**10,192,106**	**4,815,574**	Internal Plant Accounting
3	Accumulated Deferred Income Taxes	59,231,110	**10,562,919**	**5,614,243**	Internal Plant Accounting
4	Other Regulatory Assets	30,448,359	0	0	Included on Line 3, above
5	Net Investment (Line 1-2-3+4)	378,772,108	313,559,983	167,913,125	
II.	ENHANCED RETURN ON POST-2003 TRANSMISSION PLANT				
6	Enhanced Return Addition to Revenue Requirement		2,734,024	732,051	Worksheet 2b
7	PTF Transmission Plant Allocation Factor		70.1166%		

Notes: 1. Incentive for New Trans Investment
Notes: 2. Incentive for used of Advanced Tech MN Proj

The United Illuminating Company
Annual Revenue Requirements of PTF Facilities
for costs in 2009

Worksheet: 1 + 1a (Total pre-1997 and post-1996)

Line No.		Attachment F Reference	UI	Reference
	I. INVESTMENT BASE	*Section:*		
1	Transmission Plant	I (A)(1)(a)	459,345,276	Worksheet 1 + Worksheet 1a
2	General Plant	I (A)(1)(b)	9,797,200	Worksheet 1 + Worksheet 1a
3	Plant Held For Future Use	I (A)(1)(c)	25,963,558	Worksheet 1 + Worksheet 1a
4	Total Plant (Lines 1+2+3)		495,106,034	Worksheet 1 + Worksheet 1a
5	Accumulated Depreciation	I (A)(1)(d)	69,656,527	Worksheet 1 + Worksheet 1a
6	Accumulated Deferred Income Taxes	I (A)(1)(e)	57,062,943	Worksheet 1 + Worksheet 1a
7	Loss On Reacquired Debt	I (A)(1)(f)	4,261,560	Worksheet 1 + Worksheet 1a
8	Other Regulatory Assets	I (A)(1)(g)	29,333,790	Worksheet 1 + Worksheet 1a
9	Net Investment (Line 4-5-6+7+8)		401,981,914	Worksheet 1 + Worksheet 1a
10	Prepayments	I (A)(1)(h)	394,850	Worksheet 1 + Worksheet 1a
11	Materials & Supplies	I (A)(1)(i)	200,393	Worksheet 1 + Worksheet 1a
12	Cash Working Capital	I (A)(1)(j)	2,797,350	Worksheet 1 + Worksheet 1a
13	Total Investment Base (Line 9+11+12+13)		405,374,507	
	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	I (A)	53,155,363	Worksheet 1 + Worksheet 1a
15	Depreciation Expense	I (B)	11,097,695	Worksheet 1 + Worksheet 1a
16	Amortization of Loss on Reacquired Debt	I (C)	361,423	Worksheet 1 + Worksheet 1a
17	Investment Tax Credit	I (D)	(50,585)	Worksheet 1 + Worksheet 1a
18	Property Taxes	I (E)	5,851,617	Worksheet 1 + Worksheet 1a
19	Payroll Tax Expense	I (F)	586,063	Worksheet 1 + Worksheet 1a
20	Operation & Maintenance Expense	I (G)	10,124,301	Worksheet 1 + Worksheet 1a
21	Administrative & General Expense	I (H)	11,427,007	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)	827,492	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)	(15,343)	Worksheet 1 + Worksheet 1a
28	Transmission Rents Received from Electric Property	I (O)	(72,828)	Worksheet 1 + Worksheet 1a
29	Historic Revenue Requirements (Line 14 thru 28)		93,292,205	
	III. ENHANCED RETURN ON POST-2003 TRANSMISSION PLANT			
30	Enhanced Return Addition to Revenue Requirement		3,466,075	Worksheet 2b
	IV. CURRENT CALENDAR YEAR ESTIMATED INCREMENTAL REVENUE REQUIREMENT			
31	Post-96 Estimated Incremental Revenue Requirement		3,320,051	
	V. ANNUAL TRUE-UP			
32	Annual True-up		18,756,097	
	VI. TOTAL ESTIMATED REVENUE REQUIREMENT			
33	Total Estimated Revenue Requirement		118,834,428	

Shading denotes an input

	CAPITALIZATION 12/31/2009	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 501,006,582	47.88%	6.01%	2.88%	
PREFERRED STOCK		0.00%		0.00%	0.00%
COMMON EQUITY	545,373,080	52.12%	11.64%	6.07%	6.07%
TOTAL INVESTMENT RETURN	$ 1,046,379,662	100.00%		8.95%	6.07%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0895

(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)

= (0.0607 + (((12,139) + 90,459) / 97,355,559) x 0.35) / (1 - 0.35)

= 0.0331178

(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)

= (0.0607 + (((12,139) + 90,459) / 97,355,559) + 0.0331178)* 0.0825 / (1 - 0.0825)

= 0.0085083

(a)+(b)+(c) **Cost of Capital Rate** = 0.1311261

	(pre-1997 PTF)	
INVESTMENT BASE	$ 97,355,559	From Worksheet 1
x Cost of Capital Rate	0.1311261	
= Investment Return and Income Taxes	$ 12,765,855	To Worksheet 1

		CAPITALIZATION 12/31/2009	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	501,006,582	47.88%	6.01%	2.88%	
PREFERRED STOCK			0.00%		0.00%	0.00%
COMMON EQUITY		545,373,080	52.12%	11.64%	6.07%	6.07%
TOTAL INVESTMENT RETURN	$	1,046,379,662	100.00%		8.95%	6.07%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0895

(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)

= (0.0607 + (((38,446) + 286,504) / 308,018,948) x 0.35) / (1 - 0.35)

= 0.0331183

(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)

= (0.0607 + (((38,446) + 286,504) / 308,018,948) + 0.0331183)* 0.0825 / (1 - 0.0825)

= 0.0085084

(a)+(b)+(c) **Cost of Capital Rate** = 0.1311267

	(post-1996 PTF)	
INVESTMENT BASE	$ 308,018,948	From Worksheet 1a
x Cost of Capital Rate	0.1311267	
= Investment Return and Income Taxes	$ 40,389,508	To Worksheet 1a

Sheet: Worksheet 2a

The United Illuminating Company
Annual Revenue Requirements of post-2003 PTF Incremental Return
for costs in 2009
Incremental Portion of ROE at 1% Adder

		CAPITALIZATION 12/31/2009	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	501,006,582	47.88%	#N/A		
PREFERRED STOCK						
COMMON EQUITY		545,373,080	52.12%	1.00%	0.52%	0.52%
TOTAL INVESTMENT RETURN	$	1,046,379,662	100.00%		0.52%	0.52%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0052

(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)

= (0.0052 + ((0 + 0) / 313,559,983) x 0.35) / (1 - 0.35)

= 0.0028000

(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)

= (0.0052 + ((0 + 0) / 313,559,983) + 0.0028000)* 0.0825 / (1 - 0.0825)

= 0.0007193

(a)+(b)+(c) **Cost of Capital Rate** = 0.0087193

		(post-2003 PTF)	
INVESTMENT BASE	$	313,559,983	From Worksheet 1b
x Cost of Capital Rate		0.0087193	
= Investment Return and Income Taxes	$	2,734,024	To Worksheet 1b

The United Illuminating Company
Annual Revenue Requirements of post-2003 PTF Incremental Return
for costs in 2009
Incremental Portion of ROE at 1% Adder

	CAPITALIZATION 12/31/2009	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$ 501,006,582	47.88%	#N/A		
PREFERRED STOCK					
COMMON EQUITY	545,373,080	52.12%	0.50%	0.26%	0.26%
TOTAL INVESTMENT RETURN	$ 1,046,379,662	100.00%		0.26%	0.26%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0026

(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)

= (0.0026 + ((0 + 0) / 167,913,125) x 0.35) / (1 - 0.35)

= 0.0014000

(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)

= (0.0026 + ((0 + 0) / 167,913,125) + 0.0014000)* 0.0825 / (1 - 0.0825)

= 0.0003597

(a)+(b)+(c) **Cost of Capital Rate** = 0.0043597

	(post-2003 PTF)	
INVESTMENT BASE	$ 167,913,125	From Worksheet 1b
x Cost of Capital Rate	0.0043597	
= Investment Return and Income Taxes	$ 732,051	To Worksheet 1b

The United Illuminating Company - 2009

Pre-1997 PTF

Shading denotes an input

Line No.		(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated		FERC Form 1 Reference for col (1)
	Transmission Plant							
1	Transmission Plant	476,798,581		476,798,581		110,228,207	(c)	Internal Company Records
2	General Plant	90,710,456	11.2109% (a)	10,169,455	23.1184%	2,351,015		Page 207.96g
3	Total (line 1+2)			486,968,037		112,579,222		
4	Transmission Plant Held for Future Use	26,950,071		26,950,071	23.1184%	6,230,425		Page 214.47d
	Transmission Accumulated Depreciation							
5	Transmission Accum. Depreciation	69,243,722		69,243,722	23.1184%	16,008,041		Page 219.25b
5A	Transmission Cost of Removal			0	23.1184%	0		Included in Page 269.12f
6	General Plant Accum.Depreciation	27,290,215	11.2109% (a)	3,059,478	23.1184%	707,302		Page 219.28b
7	Total (line 5+6)			72,303,200		16,715,343		
	Transmission Accumulated Deferred Taxes							
8	Accumulated Deferred Taxes (281-283)	(262,293,704)	35.8417%	(94,010,488)	23.1184%	(21,733,721)		Internal Company Records
9	Accumulated Deferred Taxes (190)	97,036,108	35.8417%	34,779,378	23.1184%	8,040,436		Internal Company Records
10	Total (line 8+9)			(59,231,110)		(13,693,285)		
11	Transmission loss on Reacquired Debt	12,341,726	35.8417%	4,423,483	23.1184%	1,022,638		Page 123.1 footnote
	Other Regulatory Assets/Liabilities							
12	FAS 106	0	11.2109% (a)	0	23.1184%	0		Page 232
13	FAS 109 Asset	86,824,326	35.8417%	31,119,303	23.1184%	7,194,285		Internal Company Records
14	FAS 109 Liability	(1,871,966)	35.8417% (d)	(670,944)	23.1184%	(155,112)		Internal Company Records
15	Total (line 12+13+14)	84,952,360		30,448,359		7,039,173		
16	Transmission Prepayments	3,655,845	11.2109% (a)	409,853	23.1184%	94,751		Page 111.57c
17	Transmission Materials and Supplies	208,007		208,007	23.1184%	48,088		Page 227.8c
18	Cash Working Capital							
19	Operation & Maintenance Expense					2,429,509		Worksheet 1, Line 20
20	Administrative & General Expense					2,742,117		Worksheet 1, Line 21
21	Transmission Support Expense					827,492		Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					5,999,118		
23						0.125		x 45 / 360
24	Total (line 22 * line 23)					749,890		

(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 - 2009

post-1996 PTF

Shading denotes an input

Line No.		(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
	Transmission Plant						
1	Transmission Plant	476,798,581		476,798,581		349,117,069 (c)	Internal Company Records
2	General Plant	90,710,456	11.2109% (a)	10,169,455	73.2211%	7,446,185	Page 207.96g
3	Total (line 1+2)			486,968,037		356,563,254	
4	Transmission Plant Held for Future Use	26,950,071		26,950,071	73.2211%	19,733,133	Page 214.47d
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	69,243,722		69,243,722	73.2211%	50,701,001	Page 219.25b
5A	Transmission Cost of Removal	0		0	73.2211%	0	Included in Page 269.12f
6	General Plant Accum.Depreciation	27,290,215	11.2109% (a)	3,059,478	73.2211%	2,240,183	Page 219.28b
7	Total (line 5+6)			72,303,200		52,941,184	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	(262,293,704)	35.8417%	(94,010,488)	73.2211%	(68,835,494)	Internal Company Records
9	Accumulated Deferred Taxes (190)	97,036,108	35.8417%	34,779,378	73.2211%	25,465,836	Internal Company Records
10	Total (line 8+9)			(59,231,110)		(43,369,658)	
11	Transmission loss on Reacquired Debt	12,341,726	35.8417%	4,423,483	73.2211%	3,238,922	Page 123.1 footnote
	Other Regulatory Assets						
12	FAS 106	0	11.2109% (a)	0	73.2211%	0	Page 232
13	FAS 109 Asset	86,824,326	35.8417%	31,119,303	73.2211%	22,785,890	Internal Company Records
14	FAS 109 Liability	(1,871,966)	35.8417% (d)	(670,944)	73.2211%	(491,273)	Page 278.3f
15	Total (line 12+13+14)	84,952,360		30,448,359		22,294,617	
16	Transmission Prepayments	3,655,845	11.2109% (a)	409,853	73.2211%	300,099	Page 111.57c
17	Transmission Materials and Supplies	208,007		208,007	73.2211%	152,305	Page 227.8c
18	Cash Working Capital						
19	Operation & Maintenance Expense					7,694,792	Worksheet 1a, Line 20
20	Administrative & General Expense					8,684,890	Worksheet 1a, Line 21
21	Transmission Support Expense					0	Worksheet 1a, Line 24
22	Subtotal (line 19+20+21)					16,379,682	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					2,047,460	

(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 - 2009

pre-1997 PTF

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	**10,943,417**			10,943,417	23.1184%	2,529,943	Page 336.7f
2	General Depreciation	**5,137,378**		11.2109% (a)	575,946	23.1184%	133,150	Page 336.10f
3	Total (line 1+2)				11,519,363		2,663,093	
4	Amortization of Loss on Reacquired Debt	**1,046,701**		35.8417% (c)	375,155	23.1184%	86,730	Page 117.64c
5	Amortization of Investment Tax Credits	**146,496**		35.8417% (c)	52,507	23.1184%	12,139	Page 266.8f
	Property Taxes							
6	Transmission Property Taxes	**6,073,956**			6,073,956	23.1184%	1,404,201	Page 262.28a
7	General Property Taxes (included above)						0	Page 263.13i
8	Total (line 6+7)				6,073,956		1,404,201	
	Transmission Operation and Maintenance							
9	Operation and Maintenance	**68,778,369**						Page 321.112b
10	Transmission of Electricity by Others - #565	**57,011,534**						Page 321.96b
11	Load Dispatching - #561	**1,257,850**						Page 321.84b
12	**Station Expenses & Rents - #562 / #567	0						Worksheet 7
13	O&M less lines 10, 11 & 12	10,508,985			10,508,985	23.1184%	2,429,509	
	Transmission Administrative and General							
14	Administrative and General	**95,646,856**						Page 323.197b
15	less Property Insurance (#924)	**186,150**						Page 323.185b
16	less Regulatory Expenses (#928)	**2,851,473**						Page 323.189b
17	less General Advertising Expense (#930.1)	**26,388**						Page 323.191b
18	Subtotal [Line 14 minus (15 thru 17)]	92,582,845		11.2109% (a)	10,379,367	23.1184%	2,399,544	
19	Plus Property Insurance (#924)	186,150		35.8417% (c)	66,719	23.1184%	15,424	Page 323.185b
20	Plus FERC Assessments (#928)	**513,330**		100.0000%	513,330	23.1184%	118,674	Page 351.3d plus footn
20A	Plus CT Regulatory Expenses (#928)	**2,515,984**		35.8417% (c)	901,771	23.1184%	208,475	Page 351.1d + 351.5d
21	Plus Trans. Related General Advertising Exp.	0			0	23.1184%	0	
22	Total Transmisson A&G [line 18 plus (19 thru 21)]				11,861,188		2,742,117	
23	Payroll Tax Expense	5,426,248	(e)	11.2109% (a)	608,331	23.1184%	140,636	

(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	**38,268**	Page 263.5i
25	FICA	**5,145,115**	Page 263.4i
26 ***	Medicare	**0**	
27	CT State Unemployment	**242,866**	Page 263.12i
	Total	5,426,248	To Line 23

** Subtract Accounts #562 & #567 from O&M Expense to the extent that they include PTF Support Payments.
*** Medicare costs are included in FICA, Line 4

The United Illuminating Company - 2009

post-1996 PTF

Shading denotes an input

Line No.		(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
	Depreciation Expense						
1	Transmission Depreciation	10,943,417		10,943,417	73.2211%	8,012,888	Page 336.7f
2	General Depreciation	5,137,378	11.2109% (a)	575,946	73.2211%	421,714	Page 336.10f
3	Total (line 1+2)			11,519,363		8,434,602	
4	Amortization of Loss on Reacquired Debt	1,046,701	35.8417% (c)	375,155	73.2211%	274,693	Page 117.64c
5	Amortization of Investment Tax Credits	146,496	35.8417% (c)	52,507	73.2211%	38,446	Page 266.8f
	Property Taxes						
6	Transmission Property Taxes	6,073,956		6,073,956	73.2211%	4,447,416	Page 262.28a
7	General Property Taxes	0	0.0000% 0	0	73.2211%	0	Page 263.13i
8	Total (line 6+7)			6,073,956		4,447,416	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	68,778,369					Page 321.112b
10	Transmission of Electricity by Others - #565	57,011,534					Page 321.96b
11	Load Dispatching - #561	1,257,850					Page 321.84b
12	**Station Expenses & Rents - #562 / #567	0					Worksheet 7
13	O&M less lines 10, 11 & 12	10,508,985		10,508,985	73.2211%	7,694,792	
	Transmission Administrative and General						
14	Administrative and General	95,646,856					Page 323.197b
15	less Property Insurance (#924)	186,150					Page 323.185b
16	less Regulatory Expenses (#928)	2,851,473					Page 323.189b
17	less General Advertising Expense (#930.1)	26,388					Page 323.191b
18	Subtotal [Line 14 minus (15 thru 17)]	92,582,845	11.2109% (a)	10,379,367	73.2211%	7,599,884	
19	Plus Property Insurance (#924)	186,150	35.8417% (c)	66,719	73.2211%	48,853	Page 323.185b
20	Plus FERC Assessments (#928)	513,330	100.0000%	513,330	73.2211%	375,866	Page 351.3d plus footnote
20A	Plus CT Regulatory Expenses (#928)	2,515,984	35.8417% (c)	901,771	73.2211%	660,287	Page 351.1d + 351.5d
21	Plus Trans. Related General Advertising Exp.	0		0	73.2211%	0	
22	Total Transmisson A&G [line 18 plus (19 thru 21)]			11,861,188		8,684,890	
23	Payroll Tax Expense	5,426,248 (e)	11.2109% (a)	608,331	73.2211%	445,427	

(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

Line		Amount	Reference
24	Federal Unemployment	38,268	Page 263.5i
25	FICA	5,145,115	Page 263.4i
26 ***	Medicare	0	
27	CT State Unemployment	242,866	Page 263.12i
	Total	5,426,248	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 - 2009

pre-1997 PTF

Shading denotes an input

Line No.			FERC Form 1 Reference
	PTF Transmission Plant Allocation Factor		
1	PTF Transmission Investment	**110,228,207**	Internal Plant Accounting
2	Total Transmission Investment	476,798,581	Internal Company Records
3	Percent Allocation (line 1/2)	23.1184%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	**5,291,427**	Page 354.21b
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 of 8
6	Total Transmission Wages and Salaries (line 4+ 5)	5,291,427	
7	Total Wages and Salaries	**75,230,872**	Page 354.28b
8	Administrative and General Wages and Salaries	**28,031,907**	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)	47,198,965	
11	Percent Allocation (line 6/10)	11.2109%	
	Plant Allocation Factor		
12	Total Transmission Investment	476,798,581	Internal Company Records
13	plus Transmission-related General Plant	10,169,455	Worksheet 3 of 8, Line 2
14	Total Transmission Related Plant (line 12 + line 13)	486,968,037	
15	Total Plant in Service	**1,358,663,831**	Page 207.104g
16	Percent Allocation (line 14/15)	35.8417%	

The United Illuminating Company - 2009

Sheet: Worksheet 5a

post-1996 PTF

Shading denotes an input

Line No.			FERC Form 1 Reference
	PTF Transmission Plant Allocation Factor		
1	PTF Transmission Investment	**349,117,069**	Internal Plant Accounting
2	Total Transmission Investment	476,798,581	Internal Company Records
3	Percent Allocation (line 1/2)	73.2211%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	5,291,427	Page 354.21b
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 of 8
6	Total Transmission Wages and Salaries (line 4+ 5)	5,291,427	
7	Total Wages and Salaries	75,230,872	Page 354.28b
8	Administrative and General Wages and Salaries	28,031,907	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)	47,198,965	
11	Percent Allocation (line 6/10)	11.2109%	
	Plant Allocation Factor		
12	Total Transmission Investment	476,798,581	Internal Company Records
13	plus Transmission-related General Plant	10,169,455	Worksheet 3 of 8, Line 2
14	Total Transmission Related Plant (line 12 + line 13)	486,968,037	
15	Total Plant in Service	1,358,663,831	Page 207.104g
16	Percent Allocation (line 14/15)	35.8417%	

The United Illuminating Company - 2009

Sheet: Worksheet 6

Affiliated Company Wages and Salaries-2009

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 - 2009

Sheet: Worksheet 7

For the Year 2010

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.

Participant	PTF Supporting Facilities	The United Illuminating Company - 2009 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		27,808	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		164,409	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		360,195	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		275,080	Page 332.2g
	Substation Supply Agreements		0	
	Total =	0	827,492	

Summary of The United Illuminating Company System
Monthly Coincident Peaks for 2009
(Kilowatts)

Shading denotes an input

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
Day	15	5	2	28	22	30	28	21	24	15	30	29
Hour	1900	1900	1900	1500	1500	1500	1600	1500	1400	1900	1800	1800
The UI Co.	699,128	671,677	662,922	609,476	578,446	690,009	837,146	943,773	681,273	591,197	607,198	685,448
Hosley Substation	2,671	3,052	3,420	3,352	3,164	3,137	1,790	3,103	3,986	2,061	3,310	1,268
PSEG/Wisvest-Connecticut, (kW)	0	4,464	12,960	13,968	5,472	2,736	3,024	3,024	4,896	3,456	16,704	0
FPL Energy / Brigdeport Energy	0	0	0	0	0	0	0	0	0	0	450	3,000

Annual UI System Average 12 CP Load **697,180**

The United Illuminating Company - 2009

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%
1970	0.00	1.00	1.00	0.00%	0.00%
1971	0.00	1.00	1.00	0.00%	0.00%
1972	0.00	1.00	1.00	0.00%	0.00%
1973	0.00	1.00	1.00	0.00%	0.00%
1974	0.00	1.00	1.00	0.00%	0.00%
1975	0.00	1.00	1.00	0.00%	0.00%
1976	0.00	1.00	1.00	0.00%	0.00%
1977	2,518,016.00	2,419,271.00	4,937,287.00	8.30%	4.23%
1978	3,396,839.00	4,871,127.00	8,267,966.00	8.30%	3.41%
1979	4,574,700.00	10,925,831.00	15,500,531.00	9.90%	2.92%
1980	13,007.00	14,548.00	27,555.00	11.00%	5.19%
1981	21,022.00	7,091.00	28,113.00	9.00%	6.73%
1982	31,631.00	8,718.00	40,349.00	10.00%	7.84%
1983	40,443.00	11,964.00	52,407.00	10.25%	7.91%
1984	44,495.00	12,747.00	57,242.00	10.50%	8.16%
1985	46,083.00	16,540.00	62,623.00	10.75%	7.91%
1986	57,393.00	20,651.00	78,044.00	11.00%	8.09%
1987	54,933.00	26,486.00	81,419.00	13.00%	6.80%
1988	48,605.00	27,051.00	75,656.00	10.00%	6.58%
1989	38,968.00	26,475.00	65,443.00	12.30%	5.57%
1990	1,085.00	2,358.00	3,443.00	11.75%	3.39%
1991	1,259.00	3,931.00	5,190.00	10.88%	2.06%
1992	1,003.00	2,229.00	3,232.00	10.25%	3.18%
1993	999.00	3,068.00	4,067.00	8.75%	2.15%
1994	753.00	2,710.00	3,463.00	8.19%	1.78%
1995	390.00	2,372.00	2,762.00	8.00%	1.13%
1996	940.00	1,435.00	2,375.00	9.00%	3.56%
1997	336.00	1,239.00	1,575.00	7.50%	1.60%
1998	13.00	455.00	468.00	7.00%	0.19%
1999	575.00	1,660.00	2,235.00	7.75%	1.99%
2000	1,149.00	1,459.00	2,608.00	8.42%	3.71%
2001	1,123.00	789.00	1,912.00	9.02%	5.41%
2002	1,237.00	983.00	2,220.00	9.09%	5.41%
2003				8.08%	5.02%
2004					5.02%
2005					5.21%
2006					3.69%
2007					3.80%
2008					5.02%
2009					1.92%
		Total			146.60%
		Total divided by 41 years			3.58%
		Transmission Depreciation			$10,943,417
		Equity AFUDC Portion of Depr. Exp.			$391,286
		PTF % Pre-97			23.1184%
		Pre- 97 PTF Equity AFUDC Portion of Depr. Exp.			$90,459
		PTF % Post-96			73.2211%
		Post-96 PTF Equity AFUDC Portion of Depr. Exp.			$286,504

	2010 Estimated Plant in service
T-Replacement of HPFF Pressurizing Plants	2,900,000
T- Broadway II Substation	1,200,000
T- Water St Sub Fault Duty Mitigation	2,840,000
T- East Shore TRV	4,050,000
T-Condition Assessment of UI OH Transmission Lines	605,653
T-NERC CIP and Non-CIP	2,609,453
Other	1,500,895
Total	15,706,000

The United Illuminating Company
FERC Interest Calculation associated with Under / (Over)
True-up and Interest Calculation for 2009

1	2009 Est. Transmission Revenue Requirements (as billed)	6/09-05/10	Appendix C	18,221,320	60,387,533	ATRR - Prior Year
2	2009 Actual Annual RR			22,959,323	73,798,957	Input Panel Subtotals
3	True-up Over/(Under) (Line 1 - Line 2)			-4,738,003	-13,411,424	

	Undercollection / (Overcollection)
Pre'97	$4,738,003
Post'96	$13,411,424

Initial Billing Period	Pre 1997 Balance	Post 1996 Balance	FERC Monthly Interest Rate	Pre 1997 Interest	Post 1996 Interest
June 2009	$4,738,003	$13,411,424	0.28%	$13,266	$37,552
July 2009	4,751,269	13,448,976	0.28%	13,304	$37,657
August 2009	4,751,269	13,448,976	0.28%	13,304	$37,657
September 2009	4,751,269	13,448,976	0.27%	12,828	$36,312
October 2009	4,790,705	13,560,602	0.28%	13,414	$37,970
November 2009	4,790,705	13,560,602	0.27%	12,935	$36,614
December 2009	4,790,705	13,560,602	0.28%	13,414	$37,970
January 2010	4,830,468	13,673,155	0.28%	13,525	$38,285
February 2010	4,830,468	13,673,155	0.25%	12,076	$34,183
March 2010	4,830,468	13,673,155	0.28%	13,525	$38,285
April 2010	4,869,595	13,783,908	0.27%	13,148	$37,217
May 2010	4,869,595	13,783,908	0.28%	13,635	$38,595
		Total Interest		$158,374	$448,296
		True-Up		$4,738,003	$13,411,424
		Total TU & Int		**$4,896,377**	**$13,859,720**

The United Illuminating Company
PTF Investment By Year
As of 12/31/2009

Pre-97 PTF Year	FERC# 3530	3540	3550	3560	3570	3580	3520	3500	Pre-97 PTF
1923								4,785.24	4,785.24
1925		53,194.27		29,047.79					82,242.06
1926								166,047.67	166,047.67
1936								17,769.49	17,769.49
1937								20,576.51	20,576.51
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								239.26	239.26
1947	67.82						13,832.08		13,899.90
1948	1.59								1.59
1949	1,570.54						545.46	335.32	2,451.32
1950						442.92			442.92
1952	135.29						706.67	7,588.63	8,430.60
1953		6,813.27					1,019.89	12,676.14	20,509.30
1954	122,556.86	64,630.55		3,548.97			5,629.98	738.52	197,104.88
1955	3,532.57	20,335.11		478.23			1,554.77	2,552.11	28,452.79
1956	149.13						389.35		538.49
1957	1,698.28						3,153.53		4,851.81
1958	503,436.01	36,281.88		3,843.89	53,354.69		45,019.25	21,428.59	663,364.31
1959	135,363.74	38,759.65		76,362.51			2,983.85	127,923.35	381,393.10
1960	184,363.13				258,527.81	271,620.69	9,111.23	25,587.14	749,209.99
1961	110,072.09	392,981.98		132,082.43	533,659.12	489,080.27	14,264.06	223,131.87	1,895,271.81
1962	78,926.66	264,510.32		201,744.96		329.55	1,462.87	104,772.31	651,746.67
1963	71,610.39	77,818.49		14,813.88	957.05		12,518.11	26,967.28	204,685.19
1964	109,682.23	763.19		1,441.57			8,638.19	866.78	121,391.96
1965	139,446.20			1,689.01			4,340.13	241.05	145,716.39
1966	767,615.83	758,669.73		631,547.86	529,545.19	488,886.62	56,350.00	15,655.17	3,248,270.40
1967	424.09	971.83					3,456.90	31,556.64	36,409.46
1968	309,910.84	109,517.30	213,067.23	136,209.24	3,829.12	5,113.27	205,352.72	222,708.22	1,205,707.94
1969	1,308,319.49		1,956.12	548.85	2,165.29	1,061,216.21	105,084.79	187,231.74	2,666,522.50
1970	100,845.40		1,573.96	6,529.20	60,559.12	85,538.57	13,229.77	3,298.32	271,574.34
1971	697,908.25			4,191.55		3,152.46	22,711.96	-	727,964.23
1972	257,259.68			60,000.00			10,488.22	(949.27)	326,798.63
1973	1,593,689.59	163,137.28	2,175,313.07	809,883.37			124,386.18	355,248.46	5,221,657.96
1974	4,707,891.17	2,354.29	2,716,632.00	733,053.93		59,635.26	278,898.27	(824.80)	8,497,640.12
1975	217,839.71		41,426.49	10,957.97			47,846.38	940,518.71	1,258,589.26
1976	63,202.60	15.39					705.45	2,077.03	66,000.46
1977	8,160.91	81,979.29		210,621.90				-	300,762.10
1978	619,307.40		4,742,480.25	406,040.48				1,725.13	5,769,553.26
1979	6,713.68			38,716.77					45,430.45
1980	2,247.49		118,029.43	59,419.37					179,696.29
1981	152,577.04		415,774.29	38,962.55	5,675.72		29,794.64	15,833.13	658,617.37
1982	81,346.35		112,048.03				13,689.81	-	207,084.19
1983	26,510.28		1,560.04	60,682.30				10,986.66	99,739.29
1984	45,434.95			7,276.18			3,216.24		55,927.37
1985	80,484.92					25,600.45		55,645.32	161,730.69
1986	92,225.36								92,225.36
1987	74,697.68								74,697.68
1988	22,393.05							4,983.41	27,376.46
1989	4,376,745.89	65,160.06		5,967,775.22		1,380,105.84	675,694.57		12,465,481.58
1990	1,489,603.70	3,463,931.03		648,391.20			4,528.34		5,606,454.27
1991	2,936,533.73				851,782.51	7,256,907.43			11,045,223.67
1992	4,573,290.68				65,673.56	690,674.29	1,183,494.39	1,485,758.15	7,998,891.07
1993	4,111,824.14					103,466.78	120,505.92		4,335,796.84
1994	3,064,472.13	1,306,048.20	8,919,373.29	2,886,757.08		108,766.34	76,096.98		16,361,514.02
1995	9,441,833.95	301,344.42	866,352.49	931,130.83	13,967.63	77,322.69	889,727.96	2,437,514.65	14,959,194.62
1996	202,562.24	38,736.22		105,736.31			76,943.25	8,065.12	432,043.13
Formula1									
Pre-97 PTF	**42,914,191.29**	**7,477,430.21**	**20,325,586.69**	**14,229,075.54**	**2,564,991.19**	**12,107,859.64**	**4,067,813.68**	**6,541,259.05**	**110,228,207.29**

PTF2 Year	FERC# 3530	3540	3550	3560	3570	3580	3520	3500	Post-96 PTF
1997	731,917.80			5,944.10		96,292.33	1,334,188.08		2,168,342.31
1998	962,836.72	911,471.30		17,796.92			148,611.93		2,040,716.87
1999	-								-
2000	433,792.93	668,343.63		66,708.68			72,809.74		1,241,654.98
2001	855,055.08						66,322.37		921,377.45
2002	896,497.85	1,420,331.53		42,626.88					2,359,456.26
2003	1,093,706.89		-	-					1,093,706.89
2004	2,785,848.57			1,288,165.27		1,162,351.51	190,879.08		5,427,244.43
2005	1,491,415.12	193,047.80	62,143.88	484,721.88	398,079.45	748,951.86	7,249.40		3,385,609.39
2006	2,543,770.84	191,585.67	-	21.00	6,839.28		29,433.28	-	2,771,650.07
2007	912,505.06			490,620.70		-	133,101.26	2,791.47	1,539,018.49
2008	130,288,171.73			230,135.53	122,442,117.90	50,087,491.90	16,979,824.61	1,163,744.17	321,191,485.84
2009	3,935,592.64	886,014.40		478.81			154,720.18		4,976,806.03
Post-96 PTF	**146,931,111.23**	**4,270,794.33**	**62,143.88**	**2,627,219.77**	**122,847,036.63**	**52,095,087.60**	**19,117,139.93**	**1,166,535.64**	**349,117,069.01**

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:	17-May-10
Revenue Requirements for (year):	Calendar Year 2009
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		118,310	(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)		118,310	(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)		$118,310	(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) — $118,310 (p) = (n) + (o)

Unitil Power Corp.
Annual Revenue Requirements of PTF Facilities
for costs in 2009
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)	118,310	118,310	Worksheet 7
25	Transmission Related Expense from Generators	(L)	0	0	Worksheet 7
26	Transmission Related Taxes and Fees Charge	(M)	0	0	
27	Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	0	0	
28	Transmission Rents Received from Electric Property	(O)	0	0	
29	Total Revenue Requirements (Line 14 thru 28)		118,310	118,310	

Sheet: Worksheet 2

Unitil Power Corp.
Annual Revenue Requirements
for costs in 2009

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 = (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)

= (#DIV/0! +(0 + 0) / 0) x 0.34) / (1 - 0.34)

= #DIV/0!

(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)

= (#DIV/0! +(0 + 0) / 0) + #DIV/0!)* 0.085 / (1 - 0.085)

= #DIV/0!

(a)+(b)+(c) **Cost of Capital Rate** = #DIV/0!

		(PTF)	
INVESTMENT BASE	$	0	From Worksheet 1
x Cost of Capital Rate		#DIV/0!	
= Investment Return and Income Taxes		0	To Worksheet 1

Unitil Power Corp.

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 Use	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 Debt	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.b**
17	Transmission Materials and Supplies	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						118,310	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)						118,310	
23							0.125	x 45 / 360
24	Total (line 22 * line 23)						14,789	

(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)

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.		UPC	FERC Form 1 Reference
	PTF Transmission Plant Allocation Factor		
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	6,260	0	6,260
	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	30,956	0	30,956
	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	81,094	0	81,094
	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	118,310	0	118,310

Amount by which Support Expense exceeds Support Revenues 118,310
(To Worksheet 3, Line 21, Column 5)
See Workpaper 1.

Sheet: Worksheet 8

Summary of Unitil Power Corp. System
Monthly Coincident Peaks for 2009
(Megawatts)

Shading denotes an input

	JAN '08	FEB '08	MAR '08	APR '08	MAY '08	JUN '08	JUL '08	AUG '08	SEP '08	OCT '08	NOV '08	DEC '08
Day	0	0	0	0	0	0	0	0	0	0	0	0
Hour	0:00	0:00	0:00	0:00	0:00	0:00	0:00	0:00	0:00	0:00	0:00	0:00
UPC	-	-	-	-	-	-	-	-	-	-	-	-

Annual UPC System Average 12 CP Load **0**

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

Workpaper 1
Unitil Power Corp
Transmission Support Payment Accounts

		2009	
13-20-13-00-565-11-01-00	HQ - BECO AC (d/b/a NSTAR)	6,260.49	
13-20-13-00-565-46-00-00	HQ II TRANS EXP - BECO	$ -	
	Total	$ 6,260.49	Worksheet 7, BECo HQ Phase II - AC in MA
13-20-13-565-11-02	HQ - NEP AC	81,093.60	Worksheet 7, NEP HQ Phase II - AC in MA
13-20-13-565-11-03	HQ - Chester SVC	30,955.59	Worksheet 7, NEP Chester SVC

ISO-NE Tariff Billing
PTO Annual Transmission Revenue Requirements
per OATT Attachment F
for costs in 2009

Submitted on:	May 12, 2010
Revenue Requirements for (test year):	Calendar Year 2009
Rates Effective for the period:	June 1, 2010
through:	May 31, 2011
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	=	$ 10,741,052	(a)	$ 65,179,997	(f)
Total of Attachment F - Section J - Support Revenue		-	(b)	-	(g)
Total of Attachment F - Section K - Support Expense		1,013,305	(c)	-	(h)
Total of Attachment F - Section (L through O)		33,731	(d)	199,375	(i)
Sub Total - Sum (A through I) - J + K + (L through O)		11,788,089	(e)=(a)-(b)+(c)+(d)	65,379,372	(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)		N/A		34,488,693	(k)
Annual True-up (per Attachment C to Attachment F Implementation Rule)		(666,329)	(l)	(5,392,721)	(m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)		**$ 11,121,760**	(n)=(e)+(l)	**$ 94,475,344**	(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)	**$ 105,597,104**	(p) = (n)+(o)

VT TRANSCO
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)	$ 63,177,846	$ 373,426,415	$ 436,604,261	Worksheet 1
2		General Plant	(A)(1)(b)	3,975,243	23,496,475	27,471,718	Worksheet 1
3		Plant Held For Future Use	(A)(1)(c)	209,910	1,240,715	1,450,625	Worksheet 1
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 1
6			(A)(1)(e)	3,827,266	22,621,829	26,449,095	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)		52,612,525	310,977,950	363,590,475	
10		Prepayments	(A)(1)(h)	85,203	503,608	588,811	Worksheet 1
11		Materials & Supplies	(A)(1)(i)	681,068	4,025,589	4,706,657	Worksheet 1
12		Cash Working Capital	(A)(1)(j)	321,418	1,151,140	1,472,558	Worksheet 1
13		Total Investment Base (Line 9+10+11+12)		$ 53,700,214	$ 316,658,287	$ 370,358,501	Worksheet 1
	II.	REVENUE REQUIREMENTS					
14		Investment Return and Income Taxes	(A)	$ 6,515,479	$ 40,203,888	$ 46,719,367	Worksheet 1
15		Depreciation Expense	(B)	1,545,263	9,133,590	10,678,853	Worksheet 1
16		Amortization of Loss on Reacquired Debt	(C)	-	-	-	Worksheet 1
17		Investment Tax Credit	(D)	-	-	-	Worksheet 1
18		Property Tax Expense	(E)	1,015,934	6,004,886	7,020,820	Worksheet 1
19		Payroll Tax Expense	(F)	106,335	628,514	734,849	
20		Operation & Maintenance Expense	(G)	678,105	4,008,073	4,686,178	Worksheet 1
21		Administrative & General Expense	(H)	879,936	5,201,046	6,080,982	Worksheet 1
22		Transmission Related Integrated Facilities Charge	(I)	-	-	-	Worksheet 1
23		Transmission Support Revenue	(J)	-	-	-	Worksheet 1
24		Transmission Support Expense	(K)	1,013,305	-	1,013,305	Worksheet 1
25		Transmission Related Expense from Generators	(L)	-	-	-	
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)	Worksheet 1
28		Transmission Rents Received from Electric Property	(O)	(538)	(3,177)	(3,715)	
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	

VT TRANSCO
Annual Revenue Requirements of PTF Facilities
2008

Line No.			Attachment F Reference Section:	PRE97	POST 1996	TOTAL	Reference
	I.	INVESTMENT BASE					
1		Transmission Plant	(A)(1)(a)	$ 7,181,797	$ 335,194,735	$ 342,376,532	Worksheet 3, line 1&2 column 5
2		General Plant	(A)(1)(b)	1,405,408	20,861,443	22,266,851	Worksheet 3, line 3 column 5
3		Plant Held For Future Use	(A)(1)(c)	-	1,301,355	1,301,355	Worksheet 3, line 5 column 5
4		Total Plant (Lines 1+2+3)		8,587,205	357,357,533	365,944,738	
5		Accumulated Depreciation	(A)(1)(d)	116,360	62,267,498	62,383,858	Worksheet 3, line 8 column 5
6			(A)(1)(e)	715,002	19,853,537	20,568,539	Worksheet 3, line 11 column 5
7		Loss On Reacquired Debt	(A)(1)(f)	1,168,978	-	1,168,978	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)		8,924,821	275,236,498	284,161,319	
10		Prepayments	(A)(1)(h)	-	156,118	156,118	Worksheet 3, line 17 column 5
11		Materials & Supplies	(A)(1)(i)	49,880	4,585,750	4,635,630	Worksheet 3, line 18 column 5
12		Cash Working Capital	(A)(1)(j)	(12,316)	1,237,982	1,225,666	Worksheet 3, line 25 column 5
13		Total Investment Base (Line 9+10+11+12)		$ 8,962,385	$ 281,216,348	$ 290,178,733	
	II.	REVENUE REQUIREMENTS					
14		Investment Return and Income Taxes	(A)	$ 7,181,797	$ 39,740,921	$ 46,922,718	Worksheet 2
15		Depreciation Expense	(B)	1,405,408	7,388,054	8,793,462	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)	816,222	4,290,776	5,106,998	Worksheet 4, line 6, column 5
19		Payroll Tax Expense	(F)	116,360	611,689	728,049	Worksheet 4, line 22, column 5
20		Operation & Maintenance Expense	(G)	715,002	3,758,678	4,473,680	Worksheet 4, line 11, column 5
21		Administrative & General Expense	(H)	1,168,978	6,145,179	7,314,157	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)	995,409	-	995,409	Worksheet 6
25		Transmission Related Expense from Generators	(L)	-	-	-	Worksheet 7
26		Transmission Related Taxes and Fees Charge	(M)	49,880	262,210	312,090	
27		Revenue for ST Trans. Service Under NEPOOL Tariff	(N)	(12,316)	(64,743)	(77,059)	Attachment 7
28		Transmission Rents Received from Electric Property	(O)	(3,876)	-	(3,876)	Attachment 6
29		Total RNS Revenue Requirements before Forecast, Annual True-up and Assoc. Interest (Line 14 thru 28)		$ 12,432,864	$ 62,132,764	$ 74,565,629	
30		Forecasted PTF Revenue Requirements - 2009		-	8,464,901	8,464,901	

VT TRANSCO
Transmission Revenue Requirements of PTF Facilities
2009 True-up

	I.	APPENDIX C - ANNUAL TRUE-UP	Rate Year	PRE97	POST 1996	Total	Reference
1		ATRR for True-up = 2009 Actual	6/1/10-5/31/11	$ 11,788,089	$ 65,379,372	$ 77,167,461	Summary 6-1-10_5-31-11, line 29
2		ATRR subject to True-up = '08 TY + '09 Forecast -	6/1/09-5/31/10	12,432,864	70,597,665	83,030,529	Summary 6-1-09_5-31-10, line 31
3		Annual True-up (Line 1 - Line 2)		$ (644,776)	$ (5,218,292)	$ (5,863,068)	

VT TRANSCO
FERC Interest Calculation associated with Under / (Over)
for costs in 2009

Undercollection / (Overcollection)	
PRE97	(644,776)
Post1996	(5,218,292)

Initial Billing Period	PRE97 Balance	POST 1996 Balance	FERC Monthly Interest Rate	PRE97 Interest	POST 1996 Interest	
June 2009	(644,776)	(5,218,292)	0.28%	$ (1,805.37)	$ (14,611.22)	
July 2009	(646,581)	(5,232,904)	0.28%	(1,810.43)	(14,652.13)	
August 2009	(646,581)	(5,232,904)	0.28%	(1,810.43)	(14,652.13)	
September 2009	(646,581)	(5,232,904)	0.27%	(1,745.77)	(14,128.84)	
October 2009	(651,948)	(5,276,337)	0.28%	(1,825.45)	(14,773.74)	
November 2009	(651,948)	(5,276,337)	0.27%	(1,760.26)	(14,246.11)	
December 2009	(651,948)	(5,276,337)	0.28%	(1,825.45)	(14,773.74)	
January 2010	(657,359)	(5,320,130)	0.28%	(1,840.61)	(14,896.36)	
February 2010	(657,359)	(5,320,130)	0.25%	(1,643.40)	(13,300.33)	
March 2010	(657,359)	(5,320,130)	0.28%	(1,840.61)	(14,896.36)	
April 2010	(662,684)	(5,363,223)	0.27%	(1,789.25)	(14,480.70)	
May 2010	(662,684)	(5,363,223)	0.28%	(1,855.51)	(15,017.03)	
		Total Interest		$ (21,553)	$ (174,429)	$ (195,982)
		True-Up		(644,776)	(5,218,292)	(5,863,068)
		Total TU & Int		$ (666,329)	$ (5,392,721)	$ (6,059,050)

Shading denotes an input

TOTAL

Submitted on:	May 15, 2009
Revenue Requirements for (year):	**Calendar Yr 2008** $ 105,597,104
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	=	10,741,052	(a)	65,179,997	(f)
Total of Attachment F - Section J - Support Revenue		0	(b)		(g)
Total of Attachment F - Section K - Support Expense		1,013,305	(c)		(h)
Total of Attachment F - Section (L through O)		33,731	(d)	199,375	(i)
Sub Total - Sum (A through I) - J + K + (L through O)		11,788,089	(e)=(a)-(b)+(c)+(d)	65,379,372	(j)
Forecasted Transmission Revenue Requirements (per Attachment C to Attachment F Implementation Rule)		N/A		34,488,693	(k) = (e) + (j)
Annual True-up (per Attachment C to Attachment F Implementation Rule		($666,329)	(l)	($5,392,721)	(m)
Adjusted Sub Total - Sum (Sub Total + Forecast + True-up)		11,121,760	(n)=(e)+(l)	94,475,344	(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) **105,597,104** (p)=(n)+(o)

VT TRANSCO
Annual Revenue Requirements of PTF Facilities
for costs in 2009

Shading denotes an input

Line N	I. INVESTMENT BASE	Attachment F Reference Section:	Total	Reference
1	Transmission Plant	(A)(1)(a)	436,604,261	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	27,471,718	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	1,450,624	Worksheet 3, line 4 column 5
4			465,526,603	
5	Accumulated Depreciation	(A)(1)(d)	75,487,034	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	26,449,095	Norksheet 3, line 10 column 5
7	Loss On Reacquired Debt	(A)(1)(f)	0	Norksheet 3, line 11 column 5
8	Other Regulatory Assets	(A)(1)(g)	0	Norksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		363,590,474	
10	Prepayments	(A)(1)(h)	588,811	Norksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	4,706,657	Norksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	1,472,558	Norksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		370,358,500	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	44,935,819	Worksheet 2
	Investment Return and Income Taxes		1,783,547	Worksheet adder
15	Depreciation Expense	(B)	10,678,853	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)	7,020,820	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	734,849	*Vorksheet 4, line 23 column 5*
20	Operation & Maintenance Expense	(G)	4,686,178	Norksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	6,080,982	Norksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Ch	(I)	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	1,013,305	Worksheet 7
25	Transmission Related Expense from Generat	(L)	0	Worksheet 7
26	Transmission Related Taxes and Fees Charg	(M)	360,261	Gross Revenue Tax
27	Revenue for ST Trans. Service Under NEPO	(N)	(123,440)	Schedule 8 TOUT Revenues
28	Transmission Rents Received from Electric P	(O)	(3,715)	Rev Rent 4000-454122
29	Total Revenue Requirements (Line 14 thru 28)		77,167,460	

for costs in 2009

Shading denotes an input

		CAPITALIZATION 12/31/09	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	331,406,115	51.86%	5.52%	2.86%	
PREFERRED STOCK		0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY		307,693,258	48.15%	11.64%	5.60%	5.60%
TOTAL INVESTMEN	$	639,099,373	100.01%		8.46%	5.60%

Cost of Capital Rate=

(a) Weighted Cost c = 0.0846

(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)

= (0.0560 + 0 + 0 ` 370,358,500) x 0.34) / (1 - 0.34)

= 0.0288485

(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)

= (0.0560 + 0 + 0) / 370,358,500) + 0.0288485)* 0.085 / (1 - 0.085)

= 0.0078821

(a)+(b)+(c) **Cost of** = 0.1213306

		(PTF)	
INVESTMENT BASE	$	370,358,500	From Worksheet 1
x Cost of Capital Rate		0.1213306	
= Investment Return and Income T		44,935,819	To Worksheet 1

Shading denotes an input

.ine No.		(1) Total Factors	fo (2) Wage/Plant Allocation	(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	564,054,001		564,054,001		436,604,261	Line 1, Worksheet 5
2	General Plant	35,491,020	100.0000% (a)	35,491,020	77.4047%	27,471,718	Page 207.99g
3	Total (line 1+2)			599,545,021		464,075,979	
4	Transmission Plant Held for Future Use	1,874,078		1,874,078	77.4047%	1,450,624	Page 214.47d
	Transmission Accumulated Depreciation						
5		85,865,000		85,865,000	77.4047%	66,463,545	Page 219.25b
6	General Plant Accum.Depreciation	11,657,547	100.0000% (a)	11,657,547	77.4047%	9,023,489	Page 219.27b
7	Total (line 5+6)			97,522,547		75,487,034	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	(34,469,318)	99.1313% (c)	(34,169,883)	77.4047%	(26,449,095)	Page 113.(57-65)d
9	Accumulated Deferred Taxes (190)	0	99.1313% (c)	0	77.4047%	0	Page 111.68d
10	Total (line 8+9)			(34,169,883)		(26,449,095)	
11	Transmission loss on Reacquired Debt	0	99.1313% (c)	0	77.4047%	0	Page 111.81d
	Other Regulatory Assets						
12	FAS 106	0	100.0000% (a)	0	77.4047%	0	Page 232.30e
13	FAS 109	0	99.1313% (c)	0	77.4047%	0	Page 232.21&23e
14	Other Regulatory Liabilities (254.DK)	0	99.1313% (c)	0	77.4047%	0	Page 278.1e
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments	760,691	100.0000% (a)	760,691	77.4047%	588,811	Page 111.57c
17	Transmission Materials and Supplies	6,080,583		6,080,583	77.4047%	4,706,657	Page 227.8c
18	Cash Working Capital						
19	Operation & Maintenance Expense					4,686,178	Worksheet 1, Line 20
20	Administrative & General Expense					6,080,982	Worksheet 1, Line 21
21	Transmission Support Expense					1,013,305	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					11,780,465	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					1,472,558	

(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 Factors	(2) for costs in 2009 Wage/Plant Allocation	(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	10,173,962		10,173,962	77.4047%	7,875,125	Page 336.7b
2	General Depreciation	3,622,168	100.0000% (a)	3,622,168	77.4047%	2,803,728	Page 336.9b
3	Total (line 1+2)			13,796,130		10,678,853	
4	Amortization of Loss on Reacquired	0	99.1313% (c)	0	77.4047%	0	Page 117.64c
5	Amortization of Investment Tax Credits		99.1313% (c)	0	77.4047%	0	Page 266.8f
	Property Taxes *						
6	Transmission Property Taxes	9,070,276	99.1313% (c)	9,070,276	77.4047%	7,020,820	Page 262-263 FN.1-2
7	General Property Taxes			0	77.4047%	0	Page 262-263 FN.1-2
8	Total (line 6+7)			9,070,276		7,020,820	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	9,036,793		9,036,793	77.4047%	6,994,903	Page 321.100b
10	Transmission of Electricity by Others	435,025		435,025	77.4047%	336,730	Page 321.88b
11	Load Dispatching - #561	2,505,937		2,505,937	77.4047%	1,939,713	Page 321.84b
12	**Station Expenses & Rents - #562 / #56	41,705		41,705	1	32,282	Page 321.85b & .90b
13	O&M less lines 10, 11 & 12	6,054,126		6,054,126	`	4,686,178	
	Transmission Administrative and General						
14	Administrative and General	7,864,115					Page 323.168b
15	*less Property Insurance (#924)*	*687,775*					*Page 323.156b*
16	*less Regulatory Commission Expenses (#928)*	*236,103*					*Page 323.160b*
17	*less General Advertising Expense (#930.1)*	*0*					*Page 323.162b*
18	Subtotal [line 14 minus (15 thru 17)]	6,940,237	100.0000% (a)	6,940,237	77.4047%	5,372,070	
19	*PLUS Property Insurance alloc. using Plant Allocatio*	*687,775*	99.1313% *(c)*	681,800	77.4047%	527,745	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments*	*236,103*	99.1313% *(c)*	234,052	77.4047%	181,167	
21	*PLUS Trans. Related General Advertising Expense*	*0*	99.1313% *(c)*	0	77.4047%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*7,864,115*		*7,856,089*		*6,080,982*	
23	*Payroll Tax Expense*	*949,360*	100.0000% *(a)*	*949,360*	77.4047%	*734,849*	Footnote (d)

* Property Taxes functionalized per FERC Form 1; therefore, no need to use Plant Allocation Facto
(a) Worksheet 5 of 8, line 11
(b) Worksheet 5 of 8, line 3
(c) Worksheet 5 of 8, line 16
(d) Payroll taxes FERC Form 1, page 263.i ,263.1

Federal Unemployment	9,279	
FICA	913,065	
Medicare	0	
CT Unemployment	0	
MA Unemployment	0	
MA Universal Health	0	
VT Unemployment	27,016	
NH Unemployment	0	
Total	949,360	*To Line 23*

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

Shading denotes an input

for costs in 2009

.ine No.		VT TRANSCO	FERC Form 1 Reference	
	PTF Transmission Plant Allocation Factor			
1	PTF Transmission Investment	436,604,261	NEPOOL Catalog	
2	Total Transmission Investment	564,054,001	Page 207.58g	Includes Benn-Searsburg line
3	Percent Allocation (Line 1/Line 2)	77.4047%		
	Transmission Wages and Salaries Allocation Factor			
4	Direct Transmission Wages and Salaries	4,857,955	Page 354.21b	
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 & 6a of 8	
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	4,857,955		
7	Total Wages and Salaries	9,520,440	Page 354.28b	
8	Administrative and General Wages and Salaries	4,662,485	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)	4,857,955		
11	Percent Allocation (Line 6/Line 10)	100.0000%		`
	Plant Allocation Factor			
12	Total Transmission Investment	564,054,001	Page 207.58g	Includes Benn-Searsburg line
13	*plus Transmission-Related General Plant* *(Line 2 of Wkst. 3)*	35,491,020	*Page 207.99g*	(less General Plant owned by VI
14	*= Revised Numerator* *(Line 12 + Line 13)*	599,545,021		
15	Total Plant in Service	604,798,657	Page 207.104g	Includes Benn-Searsburg line le
16	Percent Allocation (Line 14 / Line 15)	99.1313%		

Affiliated Company Wages and Salaries

Shading denotes an input   for costs in 2009

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 and Salari		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 expens with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and

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]		44,836
	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**			10,585
	115 kV Wyman 164-167 lines			4,317
	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**			270,494
	Comerford 115 kV Substation			41,705
	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]		580,839
	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)		60,530
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
		Total =	0	1,013,305

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, 2010
Revenue Requirements for (year):	**Calendar Yr 2009** $ 11,788,089
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	=	10,741,052	(a)		(f)
Total of Attachment F - Section J - Support Revenue		0	(b)		(g)
Total of Attachment F - Section K - Support Expense		1,013,305	(c)		(h)
Total of Attachment F - Section (L through O)		33,731	(d)		(i)
Sub Total - Sum (A through I) - J + K + (L through O)		11,788,089	(e)=(a)-(b)+(c)+(d)	-	(j)

Pre-97 Revenue Requirements (per Attachment C to Attachment F Implementation Rule	11,788,089	(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	11,788,089	(l)=(k)+(b)+(g)-(h)

VT TRANSCO
Annual Revenue Requirements of PTF Facilities
for costs in 2009

Shading denotes an input

Line N	I. INVESTMENT BASE	Attachment F Reference Section:	Total	Reference
1	Transmission Plant	(A)(1)(a)	63,177,846	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	3,975,243	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	209,910	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		67,362,999	
5	Accumulated Depreciation	(A)(1)(d)	10,923,208	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	3,827,266	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)		52,612,525	
10	Prepayments	(A)(1)(h)	85,203	Vorksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	681,068	Vorksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	321,418	Vorksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		53,700,214	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	6,515,479	Worksheet 2
15	Depreciation Expense	(B)	1,545,263	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)	1,015,934	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	106,335	*Vorksheet 4, line 23 column 5*
20	Operation & Maintenance Expense	(G)	678,105	Vorksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	879,936	Vorksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Cł	(I)	0	Worksheet 7
23	Transmission Support Revenue	(J)	0	Worksheet 7
24	Transmission Support Expense	(K)	1,013,305	Worksheet 7
25	Transmission Related Expense from Generat	(L)	0	Worksheet 7
26	Transmission Related Taxes and Fees Charç	(M)	52,131	Gross Revenue Tax
27	Revenue for ST Trans. Service Under NEPO	(N)	(17,862)	Schedule 8 TOUT Revenues
28	Transmission Rents Received from Electric F	(O)	(538)	Rev Rent 4000-454122
29	Total Revenue Requirements (Line 14 thru 28)		11,788,089	

Shading denotes an input

		CAPITALIZATION 12/31/09	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTIOI
LONG-TERM DEBT	$	331,406,115	51.86%	5.52%	2.86%	
PREFERRED STOCK		0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY		307,693,258	48.15%	11.64%	5.60%	5.60%
TOTAL INVESTMEN	$	639,099,373	100.01%		8.46%	5.60%

Cost of Capital Rate=

(a) Weighted Cost o = 0.0846

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

= (0.0560 + 0 + 0 ` 53,700,214) x 0.34) / (1 - 0.34)

= 0.0288485

(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)

= (0.0560 + 0 + 0) / 53,700,214) + 0.0288485)* 0.085 / (1 - 0.085)

= 0.0078821

(a)+(b)+(c) **Cost of** = 0.1213306

		(PTF)	
INVESTMENT BASE	$	53,700,214	From Worksheet 1
x Cost of Capital Rate		0.1213306	
= Investment Return and Income T		6,515,479	To Worksheet 1

Shading denotes an input

Line No.	(1)	Total Factors	(2) Wage/Plant Allocation	(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	564,054,001		564,054,001		63,177,846	Line 1, Worksh
2	General Plant	35,491,020	100.0000% (a	35,491,020	11.2007%	3,975,243	Page 207.99g
3	Total (line 1+2)			599,545,021		67,153,089	
4	Transmission Plant Held for Future	1,874,078		1,874,078	11.2007%	209,910	Page 214.47d
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	85,865,000		85,865,000	11.2007%	9,617,481	Page 219.25b
6	General Plant Accum.Depreciation	11,657,547	100.0000% (a	11,657,547	11.2007%	1,305,727	Page 219.27b
7	Total (line 5+6)			97,522,547		10,923,208	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281	(34,469,318)	99.1313% (c	(34,169,883)	11.2007%	(3,827,266)	Page 113.(57-6
9	Accumulated Deferred Taxes (190	0	99.1313% (c	0	11.2007%	0	Page 111.82d
10	Total (line 8+9)			(34,169,883)		(3,827,266)	
11	Transmission loss on Reacquired D	0	99.1313% (c	0	11.2007%	0	Page 111.81d
	Other Regulatory Assets						
12	FAS 106	0	100.0000% (a	0	11.2007%	0	Page 232.30e
13	FAS 109	0	99.1313% (c	0	11.2007%	0	Page 232.21&2
14	Other Regulatory Liabilities (254.D	0	99.1313% (c	0	11.2007%	0	Page 278.1e
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments (165)	760,691	100.0000% (a	760,691	11.2007%	85,203	Page 111.57c
17	Transmission Materials and Suppli	6,080,583		6,080,583	11.2007%	681,068	Page 227.8c
18	Cash Working Capital						
19	Operation & Maintenance Expense					678,105	Worksheet 1, L
20	Administrative & General Expense					879,936	Worksheet 1, L
21	Transmission Support Expense					1,013,305	Worksheet 1, L
22	Subtotal (line 19+20+21)					2,571,346	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					321,418	

(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	FERC Form 1 Reference for col (1)
	Depreciation Expense						
1	Transmission Depreciation	10,173,962		10,173,962	11.2007%	1,139,555	Page 336.7b
2	General Depreciation	3,622,168	100.0000% (a)	3,622,168	11.2007%	405,708	Page 336.9b
3	Total (line 1+2)			13,796,130		1,545,263	
4	Amortization of Loss on Reacquired I	0	99.1313% (c)	0	11.2007%	0	Page 117.64c
5	Amortization of Investment Tax Credits		99.1313% (c)	0	11.2007%	0	Page 266.8f
	Property Taxes *						
6	Transmission Property Taxes	9,070,276	99.1313% (c)	9,070,276	11.2007%	1,015,934	Page 262-263 FN.1-2
7	General Property Taxes			0	11.2007%	0	Page 262-263 FN.1-2
8	Total (line 6+7)			9,070,276		1,015,934	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	9,036,793		9,036,793	11.2007%	1,012,184	Page 321.112b
10	Transmission of Electricity by Others	435,025		435,025	11.2007%	48,726	Page 321.96b
11	Load Dispatching - #561	2,505,937		2,505,937	11.2007%	280,682	Page 321.84 - 92b
12	**Station Expenses & Rents - #562 / #567	41,705		41,705	11.2007%	4,671	Page 321.85b & .90b
13	O&M less lines 10, 11 & 12	6,054,126		6,054,126	`	678,105	
	Transmission Administrative and General						
14	Administrative and General	7,864,115					Page 323.194b
15	*less Property Insurance (#924)*	*687,775*					*Page 323.156b*
16	*less Regulatory Commission Expenses (#928)*	*236,103*					*Page 323.160b*
17	*less General Advertising Expense (#930.1)*	*0*					*Page 323.162b*
18	Subtotal [line 14 minus (15 thru 17)]	6,940,237	100.0000% (a)	6,940,237	11.2007%	777,355	
19	*PLUS Property Insurance alloc. using Plant Allocatic*	*687,775*	99.1313% *(c)*	681,800	11.2007%	76,366	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments*	*236,103*	99.1313% *(c)*	234,052	11.2007%	26,215	
21	*PLUS Trans. Related General Advertising Expense*	*0*	99.1313% *(c)*	0	11.2007%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*7,864,115*		*7,856,089*		*879,936*	
23	*Payroll Tax Expense*	*949,360*	100.0000% *(a)*	*949,360*	11.2007%	*106,335*	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	9,279	
FICA	913,065	
Medicare	0	
CT Unemployment	0	
MA Unemployment	0	
MA Universal Health	0	
VT Unemployment	27,016	
NH Unemployment	0	
Total	949,360	*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 Factor	**VT TRANSCO**		
1	PTF Transmission Investment	63,177,846	NEPOOL Catalog	
2	Total Transmission Investment	564,054,001	Page 207.58g	Includes Benn-Searsburg line
3	Percent Allocation (Line 1/Line 2)	11.2007%		
	Transmission Wages and Salaries Allocation Factor			
4	Direct Transmission Wages and Salaries	4,857,955	Page 354.19b	
5	Affiliated Company Transmission Wages and Salaries	0	Worksheet 6 & 6a of 8	
6	Total Transmission Wages and Salaries (Line 4 + Line 5)	4,857,955		
7	Total Wages and Salaries	9,520,440	Page 354.25b	
8	Administrative and General Wages and Salaries	4,662,485	Page 354.24b	
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)	4,857,955		
11	Percent Allocation (Line 6/Line 10)	100.0000%		`
	Plant Allocation Factor			
12	Total Transmission Investment	564,054,001	Page 207.58g	Includes Benn-Searsburg line
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3)*	35,491,020	*Page 207.99g*	(less General Plant owned by VELCO s
14	*= Revised Numerator (Line 12 + Line 13)*	599,545,021		
15	Total Plant in Service	604,798,657	Page 207.95g	Includes Benn-Searsburg line less Gen
16	Percent Allocation (Line 14 / Line 15)	99.1313%		

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 and Salari	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 expens
with the facilities in columns (b). The totals are then linked to Worksheet 1, Lines 23 and

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]		44,836
	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**			10,585
	115 kV Wyman 164-167 lines			4,317
	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**			270,494
	Comerford 115 kV Substation			41,705
	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]		580,839
	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)		60,530
	UI Substations	330.1(n)		
	Black Pond	330.1(n)		
	Total =		0	1,013,305

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 15, 2009
Revenue Requirements for (year):	**Calendar Yr 2008** $ 65,379,372
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)	65,179,997	(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)	199,375	(i)
Sub Total - Sum (A through I) - J + K + (L through O)		0	(e)=(a)-(b)+(c)+(d)	65,379,372	(j)

Post-96 Revenue Requirements Subtotals for rate calculations under the Tariff:	65,379,372	(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	65,379,372	(l)=(k)+(b)+(g)-(h)

VT TRANSCO
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)	373,426,415	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	23,496,475	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	1,240,715	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		398,163,605	
5	Accumulated Depreciation	(A)(1)(d)	64,563,826	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	22,621,829	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)		310,977,950	
10	Prepayments	(A)(1)(h)	503,608	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	4,025,589	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	1,151,140	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		316,658,287	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	38,420,341	Worksheet 2
	Investment Return and Income Taxes Post-2003 Increme		1,783,547	Worksheet adder
15	Depreciation Expense	(B)	9,133,590	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)	6,004,886	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	628,514	*Worksheet 4, line 23 column 5*
20	Operation & Maintenance Expense	(G)	4,008,073	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	5,201,046	Worksheet 4, line 16 column 5
22	Transmission Related Integrated Facilities Char	(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)	308,130	Gross Revenue Tax
27	Revenue for ST Trans. Service Under NEPOOL	(N)	(105,578)	Schedule 8 TOUT Revenues
28	Transmission Rents Received from Electric Pro	(O)	(3,177)	Rev Rent 4000-454122
29	Total Revenue Requirements (Line 14 thru 28)		65,379,372	

VT TRANSCO

Annual Revenue Requirements
for costs in 2009

for costs in 2009

Shading denotes an input

		CAPITALIZATION 12/31/09	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	331,406,115	51.86%	5.52%	2.86%	
PREFERRED STOCK		0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY		307,693,258	48.15%	11.64%	5.60%	5.60%
TOTAL INVESTMENT	$	639,099,373	100.01%		8.46%	5.60%

Cost of Capital Rate=

(a) Weighted Cost c = 0.0846

(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)

= (0.0560 + 0 + 0 ` 316,658,287) x 0.34) / (1 - 0.34)

= 0.0288485

(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)

= (0.0560 + 0 + 0) / 316,658,287) + 0.0288485)* 0.085 / (1 - 0.085)

= 0.0078821

(a)+(b)+(c) **Cost of** = 0.1213306

		(PTF)	
INVESTMENT BASE	$	316,658,287	From Worksheet 1
x Cost of Capital Rate		0.1213306	
= Investment Return and		38,420,341	To Worksheet 1

VT TRANSCO

Annual Revenue Requirements
for costs in 2009

for costs in 2009

Shading denotes an input

		CAPITALIZATION 12/31/09	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
LONG-TERM DEBT	$	331,406,115	51.86%		0.00%	
PREFERRED STOCK		0	0.00%		0.00%	0.00%
COMMON EQUITY		307,693,258	48.15%	1.00%	0.48%	0.48%
TOTAL INVESTMENT RE	$	639,099,373	100.01%		0.48%	0.48%

Cost of Capital Rate=

(a) Weighted Cost of Cap = 0.0048

(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)

= (0.0048 + 0 + 0 ` 224,393,548) x 0.34) / (1 - 0.34)

= 0.0024727

(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)

= (0.0048 + 0 + 0) / 224,393,548) + 0.0024727)* 0.085 / (1 - 0.085)

= 0.0006756

(a)+(b)+(c) **Cost of Capi** = 0.0079483

		(PTF)	
Post-2003 INVESTMENT BASE			
PTF Transmission Plant		285,247,834	
less Accum Depreciation Rese		43,422,802	
less Accum Deferred Taxes		(17,431,484)	
Post-2003 INVESTMENT BAS		224,393,548	
INVESTMENT BASE	$	224,393,548	From Worksheet Post-2003
x Cost of Capital Rate		0.0079483	
= Investment Return and Incor		1,783,547	To Worksheet 1

VT TRANSCO
Annual Revenue Requirements of post-2003 PTF Incremental Return
for costs in 2009

Line No.		for costs in 2009 Total Transmission	Post-2003 [1] PTF	Total Transmission Reference
	I. INVESTMENT BASE			
1	Transmission Plant	564,054,001	285,247,834	Internal Plant Accounting
2	Accumulated Depreciation	85,865,000	43,422,802	Worksheet 3, line 5 column 1 + line 5A column 1
3	Accumulated Deferred Income Taxes	(34,469,318)	(17,431,484)	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)	443,719,684	224,393,548	
	II. INCREMENTAL RETURN			
6	Incremental Revenue Requirements		1,783,547	Worksheet 2a
7	PTF Transmission Plant Allocation Factor		50.5710%	

Notes: 1. line 2 column 2 = line 2 column 1 * line 7 column 2
line 3 column 2 = line 3 column 1 * line 7 column 2
line 4 column 2 = line 4 column 1 * line 7 column 2
line 7 column 2 = line 1 column 2 / line 1 column 1

Shading denotes an input

Line No.		(1) Total	for costs in 2009 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	564,054,001		564,054,001		373,426,415	Line 1, Worksh
2	General Plant	35,491,020	100.0000% (a	35,491,020	66.2040%	23,496,475	Page 207.99g
3	Total (line 1+2)			599,545,021		396,922,890	
4	Transmission Plant Held for Future	1,874,078		1,874,078	66.2040%	1,240,715	Page 214.47d
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciatior	85,865,000		85,865,000	66.2040%	56,846,064	Page 219.25b
6	General Plant Accum.Depreciation	11,657,547	100.0000% (a	11,657,547	66.2040%	7,717,762	Page 219.27b
7	Total (line 5+6)			97,522,547		64,563,826	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (28	(34,469,318)	99.1313% (c	(34,169,883)	66.2040%	(22,621,829)	Page 113.(57-6
9	Accumulated Deferred Taxes (19(	0	99.1313% (c	0	66.2040%	0	Page 111.68d
10	Total (line 8+9)			(34,169,883)		(22,621,829)	
11	Transmission loss on Reacquired I	0	99.1313% (c	0	66.2040%	0	Page 111.81d
	Other Regulatory Assets						
12	FAS 106	0	100.0000% (a	0	66.2040%	0	Page 232.30e
13	FAS 109	0	99.1313% (c	0	66.2040%	0	Page 232.21&2
14	Other Regulatory Liabilities (254.I	0	99.1313% (c	0	66.2040%	0	Page 278.1e
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments	760,691	100.0000% (a	760,691	66.2040%	503,608	Page 111.57c
17	Transmission Materials and Suppli	6,080,583		6,080,583	66.2040%	4,025,589	Page 227.8c
18	Cash Working Capital						
19	Operation & Maintenance Expense					4,008,073	Worksheet 1, L
20	Administrative & General Expense					5,201,046	Worksheet 1, L
21	Transmission Support Expense					0	Worksheet 1, L
22	Subtotal (line 19+20+21)					9,209,119	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					1,151,140	

(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 2009 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	10,173,962		10,173,962	66.2040%	6,735,570	Page 336.7b
2	General Depreciation	3,622,168	100.0000% (a)	3,622,168	66.2040%	2,398,020	Page 336.9b
3	Total (line 1+2)			13,796,130		9,133,590	
4	Amortization of Loss on Reacquired I	0	99.1313% (c)	0	66.2040%	0	Page 117.64c
5	Amortization of Investment Tax Credits		99.1313% (c)	0	66.2040%	0	Page 266.8f
	Property Taxes *						
6	Transmission Property Taxes	9,070,276	99.1313% (c)	9,070,276	66.2040%	6,004,886	Page 262-263 FN.1-2
7	General Property Taxes			0	66.2040%	0	Page 262-263 FN.1-2
8	Total (line 6+7)			9,070,276		6,004,886	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	9,036,793		9,036,793	66.2040%	5,982,718	Page 321.100b
10	Transmission of Electricity by Others	435,025		435,025	66.2040%	288,004	Page 321.88b
11	Load Dispatching - #561	2,505,937		2,505,937	66.2040%	1,659,031	Page 321.84b
12	**Station Expenses & Rents - #562 / #567	41,705		41,705	66.2040%	27,610	Page 321.85b & .90b
13	O&M less lines 10, 11 & 12	6,054,126		6,054,126	`	4,008,073	
	Transmission Administrative and General						
14	Administrative and General	7,864,115					Page 323.168b
15	*less Property Insurance (#924)*	*687,775*					*Page 323.156b*
16	*less Regulatory Commission Expenses (#928)*	*236,103*					*Page 323.160b*
17	*less General Advertising Expense (#930.1)*	*0*					*Page 323.162b*
18	Subtotal [line 14 minus (15 thru 17)]	6,940,237	100.0000% (a)	6,940,237	66.2040%	4,594,715	
19	*PLUS Property Insurance alloc. using Plant Allocatic*	*687,775*	99.1313% *(c)*	681,800	66.2040%	451,379	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments*	*236,103*	99.1313% *(c)*	234,052	66.2040%	154,952	
21	*PLUS Trans. Related General Advertising Expense*	*0*	99.1313% *(c)*	0	66.2040%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*7,864,115*		*7,856,089*		*5,201,046*	
23	*Payroll Tax Expense*	*949,360*	100.0000% *(a)*	*949,360*	66.2040%	*628,514*	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	9,279	
FICA	913,065	
Medicare	0	
CT Unemployment	0	
MA Unemployment	0	
MA Universal Health	0	
VT Unemployment	27,016	
NH Unemployment	0	
Total	949,360	*To Line 23*

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

Shading denotes an input

for costs in 2009

.ine No.			FERC Form 1 Reference	
	PTF Transmission Plant Allocation Fact	**VT TRANSCO**		
1	PTF Transmission Investment	373,426,415	NEPOOL Catalog	
2	Total Transmission Investment	564,054,001	Page 207.58g	Includes Benn-Searsburg line
3	Percent Allocation (Line 1/Line 2)	66.2040%		
	Transmission Wages and Salaries Allocation Factor			
4	Direct Transmission Wages and Salaries	4,857,955	Page 354.19b	
5	Affiliated Company Transmission Wages and S	0	Worksheet 6 & 6a of 8	
6	Total Transmission Wages and Salaries (Li	4,857,955		
7	Total Wages and Salaries	9,520,440	Page 354.25b	
8	Administrative and General Wages and Salarie	4,662,485	Page 354.24b	
9	Affiliated Company Wages and Salaries less A	0	Worksheet 6 & 6a of 8	
10	Total Wages and Salaries net of A&G (Line	4,857,955		
11	Percent Allocation (Line 6/Line 10)	100.0000%		`
	Plant Allocation Factor			
12	Total Transmission Investment	564,054,001	Page 207.58g	Includes Benn-Searsburg line
13	*plus Transmission-Related General Plant (Line*	35,491,020	*Page 207.99g*	(less General Plant owned by VELCO s
14	*= Revised Numerator (Line 12 + Line 13)*	599,545,021		
15	Total Plant in Service	604,798,657	Page 207.95g	Includes Benn-Searsburg line less Gen
16	Percent Allocation (Line 14 / Line 15)	99.1313%		

Affiliated Company Wages and Salaries

Shading denotes an i for costs in 2009

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 Workshe f

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]		
	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 2010

		Estimated Additional PTF In Service for 2010
Southern Loop		192,000,000
Lime Kiln Substation (Gorge Project)		8,600,000
Other		2,550,000
	Total	203,150,000

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VT TRANSCO

Forecasted Transmission Revenue Requirements of PTF Facilities

for costs in 2009

POST-1996

Shading denotes an input

Line No.			Period	Attachment F Reference Section:	VELCO	Reference
	I.	FORECASTED TRANSMISSION REVENUE REQUIREMENT				
1		Forecasted Transmission Plant Additions	2010	Appendix C	$203,150,000	
2		Carrying Charge Factor		Appendix C	16.98%	
3		Total Forecasted Revenue Requirements (Lines 1*2)			$34,488,693	
	II.	CARRYING CHARGE FACTOR				
4		Investment Return and Income Taxes		(A)	$38,420,341	Summary, line 14
5		Depreciation Expense		(B)	$9,133,590	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)	$6,004,886	Summary, line 18
9		Payroll Tax Expense		(F)	$628,514	Summary, line 19
10		Operation & Maintenance Expense		(G)	$4,008,073	Summary, line 20
11		Administrative & General Expense		(H)	$5,201,046	Summary, line 21
12		Total Expenses (Lines 4 thru 11)			$63,396,450	
13		PTF Transmission Plant		(A)(1)(a)	$373,426,415	Summary, line 1
14		Carrying Charge Factor (Lines 12/13)			16.98%	

VERMONT TRANSCO LLC
ROLLFORWARD PTF INVESTMENT

		Investment as of 12/31/08	Additions	Retirements	Adjustments	Investment as of 12/31/09
SUBSTATIONS						
20S	Highgate Converter	35,313.29				35,313.29
28S	Charlotte Substation	866,097.30	82,123.40		(135,237.24)	812,983.47
30S	West Rutland	15,280,154.64		27,517.56		15,252,637.08
40S	Vermont Yankee Substation	0.00	7,945,401.55			7,945,401.55
44S	Vergennes Substation	4,489,181.46			(51,028.93)	4,438,152.53
45S	Ferrisburg	1,122,669.41	253,044.80			1,375,714.21
52S	Granite	85,115,568.90	764,982.40			85,880,551.30
53S	Shelburne Substation	726,748.94	97,682.83			824,431.77
54S	Coolidge 115/345 Kv	9,142,420.33		27,569.11		9,114,851.22
61S	St Albans	44,737.83				44,737.83
62S	Essex	22,448,097.39	8,841.95		(23,789.31)	22,433,150.03
63S	Barre	208,088.30				208,088.30
64S	East Ave Substation	0.00	3,044,538.65		880,548.81	3,925,087.46
65S	Middlesex Substation	1,505,323.99	2,828.26			1,508,152.25
66S	St Johnsbury	1,389,037.05				1,389,037.05
68S	Irasburg	824,876.98			4,597.38	829,474.36
69S	Queen City Substation	4,813,632.15				4,813,632.15
70S	Ascutney	543,896.66				543,896.66
71S	North Rutland	925,859.63	255,085.58		(25,718.50)	1,155,226.71
72S	Middlebury	925,562.67				925,562.67
73S	Bennington	2,808,373.78		38,426.24	(5,530.57)	2,764,416.97
74S	New Haven	30,080,926.94		585,370.47	(531,687.31)	28,963,869.15
75S	Chelsea	147,139.20				147,139.20
76S	Blissville	10,588,949.00				10,588,949.00
77S	Hartford	3,002,467.63				3,002,467.63
80S	Georgia	1,502,190.17				1,502,190.17
81S	St Albans	1,125,855.02				1,125,855.02
82S	Sandbar	8,651,548.93	34,869.17	26,971.19		8,659,446.91
83S	Williston	5,381,700.75				5,381,700.75
89S	Cold River	1,093,944.00	1,292,792.50			2,386,736.50
91S	Berlin	1,141,855.72	4,127.20			1,145,982.92
93S	Highgate	8,803,691.85		144,965.06	(320,069.20)	8,338,657.59
95S	South Hero	384,864.41				384,864.41
98S	GMP Taft Corner	2,475,106.25	1,191,613.35		1,437,018.03	5,103,737.63
101S		0.00	531,512.20			531,512.20
		227,595,880.56	15,509,443.84	850,819.63	1,229,103.16	243,483,607.93
LINES						
	Bennington - Searsburg	1,456,022.53			0.49	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				45,122.59
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				4,680,411.39
23L	Essex-Middlebury	4,235,166.76	6,712.41	499.89		4,241,379.28
24L	Essex-Barre	1,603,676.62	13,424.82	1,669.66		1,615,431.78
25L	Essex-Burlington	0.00	16,281,428.69		237,390.85	16,518,819.54
26L	Barre-Wilder	3,303,533.31	20,137.22	2,803.84		3,320,866.69
27L	Essex-Georgia	1,387,221.31	6,712.41	507.01		1,393,426.71
28L	Barre-Comerford	3,611,286.42				3,611,286.42
29L	St. Johnsbury-Littleton	827,937.52	6,712.41	2,914.18		831,735.75
30L	West Rutland-Middlebury	4,708,892.53				4,708,892.53
31L	Rutland-Ascutney	1,901,903.62				1,901,903.62
33L	Queen City Tap	2,003,227.09				2,003,227.09
35L	WEST RUTL MIDDLEBURY 345K	49,164,553.32				49,164,553.32
37L	Vernon-Scobie Tie	437,797.23				437,797.23
38L	Vernon-Northfield Tie	385,133.00				385,133.00
39L	St. Johnsbury-Irasburg	2,933,682.27				2,933,682.27
40L	Vernon-Coolidge	7,535,584.41				7,535,584.41
41L	Coolidge-West Rutland	8,487,201.11				8,487,201.11
42L	Richford-New Highgate 120	1,387,348.35	10,068.56	9,035.35		1,388,381.56
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	57,425,905.80	3,649,047.72			61,074,953.52
49L	Duxbury - Stowe	0.00	1,521,069.46			1,521,069.46
L34	West Rutland - Whitehall	930,132.48	26,849.63	3,474.80		953,507.31
		171,362,002.76	21,542,163.33	20,904.73	237,391.34	193,120,652.70
	TOTAL PTF Facilities	398,957,883.32	37,051,607.17	871,724.36	1,466,494.50	$\boxed{436,604,260.63}$

HIGHGATE JOINT OWNERS	Revenue Requirements Year End 2009
City of Burlington Electric Department	230,807.00
Central Vermont Public Service Corporation	3,716,825.00
Vermont Marble	17,165.00
Green Mountain Power Corporation	1,543,131.00
Vermont Public Power Supply Authority	217,214.00
Johnson	13,575.00
	5,738,717.00

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 15, 2010	RTO ROE filing	
Revenue Requirements for (year):	**Calendar Yr 2009** $ 5,738,717		
Customer:	**Highgate Joint Owners**		
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 =	5,738,717	(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)	5,738,717	(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:	5,738,717	(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)	5,738,717	(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 13, 2010	RTO ROE filing
Revenue Requirements for (year):	**Calendar Yr 2009** $ 230,807	
Customer:	City of 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 =	230,808	(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)	(1)	(d)		(i)
Sub Total - Sum (A through I) - J + K + (L through O)	230,807	(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:	230,807	(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)	230,807	(l)=(k)+(b)+(g)-(h)

Sheet: Worksheet 1

City of Burlington Electric Department

Annual Revenue Requirements of PTF Facilities

for costs in 2009

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)	2,331,401	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)		2,331,401	
5	Accumulated Depreciation	(A)(1)(d)	1,391,834	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)		939,567	
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)	6,724	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		946,291	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	72,675	Worksheet 2
15	Depreciation Expense	(B)	63,895	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)	40,444	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	0	*Worksheet 4, line 23 column 5*
20	Operation & Maintenance Expense	(G)	49,658	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	4,136	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)		230,808	

City of Burlington Electric Department

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	$	78,561,158	63.11%	5.36%	3.38%	
PREFERRED STOCK		0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY		45,916,065	36.90%	11.64%	4.30%	4.30%
TOTAL INVESTMENT	$	124,477,223	100.01%		7.68%	4.30%

Cost of Capital Rate=

(a) Weighted Cost of (= 0.0768

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

= (0.0430 + 0 + 0 ` 946,291) x 0) / (1 - 0)

= 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)

= (0.0430 + 0 + 0) / 946,291) + 0.0000000)* 0 / (1 - 0)

= 0.0000000

(a)+(b)+(c) **Cost of C** = 0.0768000

		(PTF)	
INVESTMENT BASE	$	946,291	From Worksheet 1
x Cost of Capital Rate		0.0768000	
= Investment Return and In		72,675	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	2,516,876		2,516,876		2,331,401	Line 1, Workshe
2	General Plant	9,747,000	0.0000% (a	0	92.6307%	0	Page 207.99g
3	Total (line 1+2)	12,263,876		2,516,876		2,331,401	
4	Transmission Plant Held for Future Use	0		0	92.6307%	0	Page 214.47d
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	1,502,562		1,502,562	92.6307%	1,391,834	Page 219.25b
6	General Plant Accum.Depreciation	5,745,815	0.0000% (a	0	92.6307%	0	Page 219.28b
7	Total (line 5+6)			1,502,562		1,391,834	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	0	2.0456% (c	0	92.6307%	0	Page 113.57d
9	Accumulated Deferred Taxes (190)	0	2.0456% (c	0	92.6307%	0	Page 111.82c
10	Total (line 8+9)			0		0	
11	Transmission loss on Reacquired Debt	0	2.0456% (c	0	92.6307%	0	Page 111.81d
	Other Regulatory Assets						
12	FAS 106	0	0.0000% (a	0	92.6307%	0	Page 232.30e
13	FAS 109	0	2.0456% (c	0	92.6307%	0	Page 232.1,2,3f
14	Other Regulatory Liabilities (254.DK)	0	2.0456% (c	0	92.6307%	0	Page 278.1,2f
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments	0	0.0000% (a	0	92.6307%	0	Page 110.57c
17	Transmission Materials and Supplies	0		0	92.6307%	0	Page 227.8c
18	Cash Working Capital						
19	Operation & Maintenance Expense					49,658	Worksheet 1, Lir
20	Administrative & General Expense					4,136	Worksheet 1, Lir
21	Transmission Support Expense					0	Worksheet 1, Lir
22	Subtotal (line 19+20+21)					53,794	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					6,724	

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

City of Burlington Electric Department

Sheet: Worksheet 4

Shading denotes an input

Line No.		(1) Total	(2) for costs in 2009 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	68,978		68,978	92.6307%	63,895	Page 336.7b
2	General Depreciation	248,610	0.0000% (a)	0	92.6307%	0	Page 336.10b
3	Total (line 1+2)			68,978		63,895	
4	Amortization of Loss on Reacquired Debt	0	2.0456% (c)	0	92.6307%	0	Page 117.64c
5	Amortization of Investment Tax Credits	0	2.0456% (c)	0	92.6307%	0	Page 266.8f
	Property Taxes *						
6	Transmission Property Taxes	2,134,428	2.0456% (c)	43,662	92.6307%	40,444	Page 262-263 FN.1-2
7	General Property Taxes	0	0.0000%	0	92.6307%	0	Page 262-263 FN.1-2
8	Total (line 6+7)			43,662		40,444	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	4,069,309		4,069,309	92.6307%	3,769,429	Page 321.112b
10	Transmission of Electricity by Others - #565	4,015,700		4,015,700	92.6307%	3,719,771	Page 321.96b
11	Load Dispatching - #561	0		0	92.6307%	0	Page 321.84b
12	**Station Expenses & Rents - #562 / #567	0		0	92.6307%	0	Page 321.93b & .98b
13	O&M less lines 10, 11 & 12	53,609		53,609	`	49,658	
	Transmission Administrative and General						
14	Administrative and General	3,083,453					Page 323.197b
15	*less Property Insurance (#924)*	*191,128*					*Page 323.185b*
16	*less Regulatory Commission Expenses (#928)*	*27,125*					*Page 323.189b*
17	*less General Advertising Expense (#930.1)*	*0*					*Page 323.191b*
18	Subtotal [line 14 minus (15 thru 17)]	2,865,201	0.0000% (a)	0	92.6307%	0	
19	*PLUS Property Insurance alloc. using Plant Allocation*	*191,128*	2.0456% *(c)*	3,910	92.6307%	3,622	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	*27,125*	2.0456% *(c)*	555	92.6307%	514	
21	*PLUS Trans. Related General Advertising Expense*	*0*	2.0456% *(c)*	0	92.6307%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*3,083,453*		*4,465*		*4,136*	
23	*Payroll Tax Expense*	*636,876*	0.0000% *(a)*	*0*	92.6307%	*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	*515,712*	
Medicare	*121,164*	
CT Unemployment		
MA Unemployment		
MA Universal Health		
VT Unemployment	*0*	
NH Unemployment	*0*	
Total	636,876	*To Line 23*

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

0	
0	net

Shading denotes an input

Line No.			FERC Form 1 Reference
	PTF Transmission Plant Allocation Factor		
1	PTF Transmission Investment	2,331,401	NEPOOL Catalog
2	Total Transmission Investment	2,516,876	Page 207.58g
3	Percent Allocation (Line 1/Line 2)	92.6307%	
	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	8,422,385	Page 354.28b
8	Administrative and General Wages and Salaries	1,469,001	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)	6,953,384	
11	Percent Allocation (Line 6/Line 10)	0.0000%	`
	Plant Allocation Factor		
12	Total Transmission Investment	2,516,876	Page 207.58g
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3*	0	*Worksheet 3, Line 2*
14	*= Revised Numerator (Line 12 + Line 13)*	2,516,876	
15	Total Plant in Service	123,037,638	Page 207.104g
16	Percent Allocation (Line 14 / Line 15)	2.0456%	

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 13, 2010	RTO ROE filing
Revenue Requirements for (year):	**Calendar Yr 2009** $ 3,716,825	
Customer:	Central Vermont Public Service	
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 =	3,716,826	(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)	(1)	(d)		(i)
Sub Total - Sum (A through I) - J + K + (L through O)	3,716,825	(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:	3,716,825	(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)	3,716,825	(l)=(k)+(b)+(g)-(h)

Sheet: Worksheet 1

Central Vermont Public Service Corporation
Annual Revenue Requirements of PTF Facilities
for costs in 2009

Shading denotes an input

Line N	I. INVESTMENT BASE	Attachment F Reference Section:	Total	Reference
1	Transmission Plant	(A)(1)(a)	14,672,330	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	591,737	Worksheet 3, line 2 column 5
3	Plant Held For Future Use	(A)(1)(c)	1,102	Worksheet 3, line 4 column 5
4	Total Plant (Lines 1+2+3)		15,265,169	
5	Accumulated Depreciation	(A)(1)(d)	6,047,478	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	1,456,636	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)	132,057	Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		7,893,112	
10	Prepayments	(A)(1)(h)	316,150	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	152,415	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	224,386	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		8,586,063	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	1,222,477	Worksheet 2
15	Depreciation Expense	(B)	378,360	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)	(8,236)	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	287,972	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	41,162	*Worksheet 4, line 23 column 5*
20	Operation & Maintenance Expense	(G)	1,197,836	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	597,255	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)		3,716,826	

Sheet: Worksheet 2

Central Vermont Public Service
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	$	178,300,000	37.77%	6.36%	2.40%	
PREFERRED STOCK		8,904,186	1.89%	5.30%	0.10%	
COMMON EQUITY		284,875,869	60.35%	11.64%	7.02%	7.02%
TOTAL INVESTMENT	$	472,080,055	100.01%		9.52%	7.02%

Cost of Capital Rate=

(a) Weighted Cost of (= 0.0952

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

= (0.0702 + (8,236) + 0 ` 8,586,063) x 0.35) / (1 - 0.35)

= 0.0372835

(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)

= (0.0702 + (8,236) + 0) / 8,586,063) + 0.0372835)* 0.085 / (1 - 0.085)

= 0.0098957

(a)+(b)+(c) **Cost of C** = 0.1423792

		(PTF)	
INVESTMENT BASE	$	8,586,063	From Worksheet 1
x Cost of Capital Rate		0.1423792	
= Investment Return and In		1,222,477	To Worksheet 1

Shading denotes an input

Line No.		(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (
	Transmission Plant						
1	Transmission Plant	72,892,665		72,892,665		14,672,330	Line 1, Workshe
2	General Plant	37,777,059	7.7819% (a	2,939,769	20.1287%	591,737	Page 207.99g
3	Total (line 1+2)			75,832,434		15,264,067	
4	Transmission Plant Held for Future Use	42,819	12.7843%	5,474	20.1287%	1,102	Page 214.47d
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	28,850,134		28,850,134	20.1287%	5,807,157	Page 219.25b
6	General Plant Accum.Depreciation	15,342,337	7.7819% (a	1,193,924	20.1287%	240,321	Page 219.28b
7	Total (line 5+6)			30,044,058		6,047,478	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	85,719,353	12.7843% (c	10,958,619	20.1287%	2,205,828	Page 113.57d
9	Accumulated Deferred Taxes (190)	(29,113,898)	12.7843% (c	(3,722,008)	20.1287%	(749,192)	Page 111.82c
10	Total (line 8+9)			7,236,611		1,456,636	
11	Transmission loss on Reacquired Debt	0	12.7843% (c	0	20.1287%	0	Page 111.81d
	Other Regulatory Assets						
12	FAS 106	1,221,020	7.7819% (a	95,018	20.1287%	19,126	Page 232.30e
13	FAS 109	4,388,553	12.7843% (c	561,046	20.1287%	112,931	Page 232.1,2,3f
14	Other Regulatory Liabilities(106, 109)	0	12.7843% (c	0	20.1287%	0	Page 278.1,2f
15	Total (line 12+13+14)	5,609,573		656,064		132,057	
16	Transmission Prepayments	20,183,305	7.7819% (a	1,570,642	20.1287%	316,150	Page 110.57c
17	Transmission Materials and Supplies	757,200		757,200	20.1287%	152,415	Page 227.8c
18	Cash Working Capital						
19	Operation & Maintenance Expense					1,197,836	Worksheet 1, Lii
20	Administrative & General Expense					597,255	Worksheet 1, Lii
21	Transmission Support Expense					0	Worksheet 1, Lii
22	Subtotal (line 19+20+21)					1,795,091	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					224,386	

(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	FERC Form 1 Reference for col (1)
	Depreciation Expense						
1	Transmission Depreciation	1,623,941		1,623,941	20.1287%	326,878	Page 336.7f
2	General Depreciation	3,286,630	7.7819% (a)	255,762	20.1287%	51,482	Page 336.10f
3	Total (line 1+2)			1,879,703		378,360	
4	Amortization of Loss on Reacquired Debt	0	12.7843% (c)	0	20.1287%	0	Page 117.64c
5	Amortization of Investment Tax Credits	320,047	12.7843% (c)	40,916	20.1287%	8,236	Page 266.8f
	Property Taxes						
6	Transmission Property Taxes	11,190,696	12.7843% (c)	1,430,652	20.1287%	287,972	Page 262-263 FN.1-2
7	General Property Taxes *	0	12.7843%	0	20.1287%	0	Page 262-263 FN.1-2
8	Total (line 6+7)			1,430,652		287,972	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	33,782,941		33,782,941	20.1287%	6,800,067	Page 321.112b
10	Transmission of Electricity by Others - #565	27,773,744		27,773,744	20.1287%	5,590,494	Page 321.96b
11	Load Dispatching - #561	58,310		58,310	20.1287%	11,737	Page 321.84b
12	**Station Expenses & Rents - #562 / #567	0		0	20.1287%	0	Page 321.93b & .98b
13	O&M less lines 10, 11 & 12	5,950,887		5,950,887	`	1,197,836	
	Transmission Administrative and General						
14	Administrative and General	37,247,746					Page 323.197b
15	*less Property Insurance (#924)*	*791,768*					*Page 323.185b*
16	*less Regulatory Commission Expenses (#928)*	*579,550*					*Page 323.189b*
17	*less General Advertising Expense (#930.1)*	*0*					*Page 323.191b*
18	Subtotal [line 14 minus (15 thru 17)]	35,876,428	7.7819% (a)	2,791,864	20.1287%	561,966	
19	*PLUS Property Insurance alloc. using Plant Allocation*	*791,768*	12.7843%	101,222	20.1287%	20,375	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	*579,550*	12.7843% *(c)*	74,091	20.1287%	14,914	
21	*PLUS Trans. Related General Advertising Expense*	*0*	12.7843% *(c)*	0	20.1287%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*37,247,746*		*2,967,177*		*597,255*	
23	*Payroll Tax Expense*	*2,627,843*	7.7819% *(a)*	*204,496*	20.1287%	*41,162*	Footnote (d)

* Property Taxes not functionalized per FERC Form 1; therefore, 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	*25,552*	
FICA	*2,528,549*	
Medicare	*0*	
CT Unemployment		
MA Unemployment		
MA Universal Health		
VT Unemployment	*73,742*	
NH Unemployment	*0*	
Total	2,627,843	*To Line 23*

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

Shading denotes an input

Line No.			FERC Form 1 Reference
	PTF Transmission Plant Allocation Factor		
1	PTF Transmission Investment	14,672,330	NEPOOL Catalog
2	Total Transmission Investment	72,892,665	Page 207.58g
3	Percent Allocation (Line 1/Line 2)	20.1287%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	1,771,142	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	1,771,142	
7	Total Wages and Salaries	36,833,880	Page 354.28b
8	Administrative and General Wages and Salaries	14,074,086	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)	22,759,794	
11	Percent Allocation (Line 6/Line 10)	7.7819%	`
	Plant Allocation Factor		
12	Total Transmission Investment	72,892,665	Page 207.58g
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3*	2,939,769	*Worksheet 3, Line 2*
14	*= Revised Numerator (Line 12 + Line 13)*	75,832,434	
15	Total Plant in Service	593,168,460	Page 207.100g
16	Percent Allocation (Line 14 / Line 15)	12.7843%	

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 13, 2010	RTO ROE filing
Revenue Requirements for (year):	**Calendar Yr 2009** $ 1,543,131	
Customer:	Green Mountain Power Corporation	
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 =	1,543,132	(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)	(1)	(d)		(i)
Sub Total - Sum (A through I) - J + K + (L through O)	1,543,131	(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:	1,543,131	(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)	1,543,131	(l)=(k)+(b)+(g)-(h)

Sheet: Worksheet 1

Green Mountain Power Corporation
Annual Revenue Requirements of PTF Facilities
for costs in 2009

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)	307,789	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)		10,648,699	
5	Accumulated Depreciation	(A)(1)(d)	5,043,008	Worksheet 3, line 7 column 5
6	Accumulated Deferred Income Taxes	(A)(1)(e)	1,230,001	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)	74,089	Worksheet 3, line 14 column 5
9	Net Investment (Line 4-5-6+7+8)		4,449,779	
10	Prepayments	(A)(1)(h)	12,438	Worksheet 3, line 15 column 5
11	Materials & Supplies	(A)(1)(i)	9,748	Worksheet 3, line 16 column 5
12	Cash Working Capital	(A)(1)(j)	53,889	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		4,525,854	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	617,551	Worksheet 2
15	Depreciation Expense	(B)	302,774	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)	(6,608)	Worksheet 4, line 5 column 5
18	Property Tax Expense	(E)	198,304	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	0	*Worksheet 4, line 23 column 5*
20	Operation & Maintenance Expense	(G)	320,096	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	111,015	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)		1,543,132	

Green Mountain Power Corporation

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	$	140,000,000	44.85%	6.57%	2.95%	
PREFERRED STOCK		0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY		172,168,645	55.16%	11.64%	6.42%	6.42%
TOTAL INVESTMENT RETURN	$	312,168,645	100.01%		9.37%	6.42%

Cost of Capital Rate=

(a) Weighted Cost of Capital = 0.0937

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

= (0.0642 + (6,608) + 0 ` 4,525,854) x 0.35) / (1 - 0.35)

= 0.0337830

(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)

= (0.0642 + (6,608) + 0) / 4,525,854) + 0.0337830)* 0.085 / (1 - 0.085)

= 0.0089666

(a)+(b)+(c) **Cost of Capital Rate** = 0.1364496

		(PTF)	
INVESTMENT BASE	$	4,525,854	From Worksheet 1
x Cost of Capital Rate		0.1364496	
= Investment Return and Income Taxes		617,551	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	42,631,345		42,631,345		10,340,910	Line 1, Workshe
2	General Plant	40,545,003	3.1296% (a	1,268,887	24.2566%	307,789	Page 207.99g
3	Total (line 1+2)			43,900,232		10,648,699	
4	Transmission Plant Held for Future Use	0		0	24.2566%	0	Page 214.47d
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	20,404,013		20,404,013	24.2566%	4,949,320	Page 219.25b
6	General Plant Accum.Depreciation	12,341,569	3.1296% (a	386,239	24.2566%	93,688	Page 219.28b
7	Total (line 5+6)			20,790,252		5,043,008	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	83,255,090	10.5132% (c	8,752,774	24.2566%	2,123,125	Page 113.57d
9	Accumulated Deferred Taxes (190)	(35,022,495)	10.5132% (c	(3,681,985)	24.2566%	(893,124)	Page 111.82c
10	Total (line 8+9)			5,070,789		1,230,001	
11	Transmission loss on Reacquired Debt	0	10.5132% (c	0	24.2566%	0	Page 111.81d
	Other Regulatory Assets						
12	FAS 106	0	3.1296% (a	0	24.2566%	0	Page 232.30e
13	FAS 109	1,785,508	10.5132% (c	187,714	24.2566%	45,533	Page 232.1,2,3f
14	Other Regulatory Liabilities (254.DK)	1,119,771	10.5132% (c	117,724	24.2566%	28,556	Page 278.1,2f
15	Total (line 12+13+14)	2,905,279		305,438		74,089	
16	Transmission Prepayments	1,638,451	3.1296% (a	51,277	24.2566%	12,438	Page 110.57c
17	Transmission Materials and Supplies	40,185		40,185	24.2566%	9,748	Page 227.8c
18	Cash Working Capital						
19	Operation & Maintenance Expense					320,096	Worksheet 1, Lir
20	Administrative & General Expense					111,015	Worksheet 1, Lir
21	Transmission Support Expense					0	Worksheet 1, Lir
22	Subtotal (line 19+20+21)					431,111	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					53,889	

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

Sheet: Worksheet 4

Green Mountain Power Corporation

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	1,196,133		1,196,133	24.2566%	290,141	Page 336.7b
2	General Depreciation	1,664,099	3.1296% (a)	52,079	24.2566%	12,633	Page 336.10b
3	Total (line 1+2)			1,248,212		302,774	
4	Amortization of Loss on Reacquired Debt	0	10.5132% (c)	0	24.2566%	0	Page 117.64c
5	Amortization of Investment Tax Credits	259,138	10.5132% (c)	27,244	24.2566%	6,608	Page 266.8f
	Property Taxes *						
6	Transmission Property Taxes	5,992,362	10.5132% (c)	629,989	24.2566%	152,814	Page 262-263 FN.1-2
7	General Property Taxes	5,992,362	3.1296%	187,536	24.2566%	45,490	Page 262-263 FN.1-2
8	Total (line 6+7)			817,525		198,304	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	27,348,175		27,348,175	24.2566%	6,633,737	Page 321.112b
10	Transmission of Electricity by Others - #565	25,644,483		25,644,483	24.2566%	6,220,480	Page 321.96b
11	Load Dispatching - #561	70,236		70,236	24.2566%	17,037	Page 321.84b
12	**Station Expenses & Rents - #562 / #567	313,827		313,827	24.2566%	76,124	Page 321.93b & .98b
13	O&M less lines 10, 11 & 12	1,319,629		1,319,629	`	320,096	
	Transmission Administrative and General						
14	Administrative and General	12,962,615					Page 323.197b
15	*less Property Insurance (#924)*	*410,354*					*Page 323.185b*
16	*less Regulatory Commission Expenses (#928)*	*324,889*					*Page 323.189b*
17	*less General Advertising Expense (#930.1)*	*73,339*					*Page 323.191b*
18	Subtotal [line 14 minus (15 thru 17)]	12,154,033	3.1296% (a)	380,370	24.2566%	92,265	
19	*PLUS Property Insurance alloc. using Plant Allocation*	*410,354*	10.5132% *(c)*	43,141	24.2566%	10,465	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	*324,889*	10.5132% *(c)*	34,156	24.2566%	8,285	
21	*PLUS Trans. Related General Advertising Expense*	*0*	10.5132% *(c)*	0	24.2566%	0	
22	Total A&G [line 18 plus (19 thru 21)]	*12,889,276*		*457,667*		*111,015*	
23	*Payroll Tax Expense*		3.1296% *(a)*	*0*	24.2566%	*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	*12,166*	
FICA	*1,217,127*	
Medicare	*0*	
CT Unemployment		
MA Unemployment		
MA Universal Health		
VT Unemployment	*74,816*	
NH Unemployment	*0*	
Total	1,304,109	*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.		GMP	FERC Form 1 Reference
	PTF Transmission Plant Allocation Factor	**GMP**	
1	PTF Transmission Investment	10,340,910	NEPOOL Catalog
2	Total Transmission Investment	42,631,345	Page 207.58g
3	Percent Allocation (Line 1/Line 2)	24.2566%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	237,211	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	237,211	
7	Total Wages and Salaries	11,613,281	Page 354.28b
8	Administrative and General Wages and Salaries	4,033,631	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)	7,579,650	
11	Percent Allocation (Line 6/Line 10)	3.1296%	`
	Plant Allocation Factor		
12	Total Transmission Investment	42,631,345	Page 207.58g
13	*plus Transmission-Related General Plant (Line 2 of Wkst. 3*	1,268,887	*Worksheet 3, Line 2*
14	*= Revised Numerator (Line 12 + Line 13)*	43,900,232	
15	Total Plant in Service	417,572,666	Page 207.104g
16	Percent Allocation (Line 14 / Line 15)	10.5132%	

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 13, 2010	RTO ROE filing
Revenue Requirements for (year):	**Calendar Yr 2009** $ 217,214	
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 =	217,215	(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)	(1)	(d)		(i)
Sub Total - Sum (A through I) - J + K + (L through O)	217,214	(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:	217,214	(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)	217,214	(l)=(k)+(b)+(g)-(h)

Sheet: Worksheet 1

Vermont Public Power Supply Authority

Annual Revenue Requirements of PTF Facilities

Shading denotes an input

Line N	I. INVESTMENT BASE	Attachment F Reference Section:	Total	Reference
1	Transmission Plant	(A)(1)(a)	3,059,672	Worksheet 3, line 1 column 5
2	General Plant	(A)(1)(b)	24,089	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)		3,083,761	
5	Accumulated Depreciation	(A)(1)(d)	2,798,453	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)		285,308	
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)	16,614	Worksheet 3, line 23 column 5
13	Total Investment Base (Line 9+10+11+12)		301,922	

	II. REVENUE REQUIREMENTS			
14	Investment Return and Income Taxes	(A)	35,144	Worksheet 2
15	Depreciation Expense	(B)	8,198	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)	40,963	Worksheet 4, line 8 column 5
19	Payroll Tax Expense	(F)	0	*Worksheet 4, line 23 column 5*
20	Operation & Maintenance Expense	(G)	48,591	Worksheet 4, line 13 column 5
21	Administrative & General Expense	(H)	84,319	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)		217,215	

Vermont Public Power Supply Authority

Annual Revenue Requirements
for costs in 2009

Shading denotes an input

		CAPITALIZATION 12/31/2009	CAPITALIZATION RATIOS	COST OF CAPITAL		EQUITY PORTION
LONG-TERM DEBT	$	0	0.00%	0.00%		
PREFERRED STOCK		0	0.00%	0.00%		0.00%
COMMON EQUITY		386,225	100.01%	11.64%		11.64%
TOTAL INVESTMENT	$	386,225	100.01%			11.64%

Cost of Capital Rate=

(a) Weighted Cost of (= 0.1164

(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
=	0.1164	+	0	+	0	301,922)	x	0
(	1						-	0
=	0.0000000							

(c) State Income Tax =

	R.O.E. +	(	PTF Inv. (Tax Credit	+	Eq. AFUDC of Deprec. Ex	PTF Inv. Base)	+	Federal Income Tax
(	1						-	State Income Tax Rate
=	0.1164	+	0	+	0	301,922)	+	0.0000000
(	1						-	0
=	0.0000000							

(a)+(b)+(c) **Cost of C** = 0.1164000

		(PTF)	
INVESTMENT BASE	$	301,922	From Worksheet 1
x Cost of Capital Rate		0.1164000	
= Investment Return and In		35,144	To Worksheet 1

Shading denotes an input

Line No.		(1) Total	(2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)
	Transmission Plant						
1	Transmission Plant	3,059,672		3,059,672		3,059,672	Line 1, Worksheet 5
2	General Plant	24,089	100% (a	24,089	100%	24,089	Page 207.90g
3	Total (line 1+2)			3,083,761		3,083,761	
4	Transmission Plant Held for Future Use	0		0	100%	0	Page 214.47d
	Transmission Accumulated Depreciation						
5	Transmission Accum. Depreciation	2,774,364		2,774,364	100%	2,774,364	Page 219.25b
6	General Plant Accum.Depreciation	24,089	100% (a	24,089	100%	24,089	Page 219.28b
7	Total (line 5+6)			2,798,453		2,798,453	
	Transmission Accumulated Deferred Taxes						
8	Accumulated Deferred Taxes (281-283)	0	100% (c)	0	100%	0	Page 113.57d
9	Accumulated Deferred Taxes (190)	0	100% (c)	0	100%	0	Page 111.82c
10	Total (line 8+9)			0		0	
11	Transmission loss on Reacquired Debt	0	100% (c)	0	100%	0	Page 111.67d
	Other Regulatory Assets						
12	FAS 106	0	100% (a	0		0	Page 232.30e
13	FAS 109	0	100% (c)	0	100%	0	Page 232.1,2,3f
14	Other Regulatory Liabilities (254.DK)	0	100% (c)	0	100%	0	Page 278.1,2f
15	Total (line 12+13+14)	0		0		0	
16	Transmission Prepayments	0	100% (a	0		0	Page 110.57c
17	Transmission Materials and Supplies	0		0		0	Page 227.8c
18	Cash Working Capital						
19	Operation & Maintenance Expense					48,591	Worksheet 1, Line 20
20	Administrative & General Expense					84,319	Worksheet 1, Line 21
21	Transmission Support Expense					0	Worksheet 1, Line 24
22	Subtotal (line 19+20+21)					132,910	
23						0.125	x 45 / 360
24	Total (line 22 * line 23)					16,614	

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

Vermont Public Power Supply Authority

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	8,075		8,075	100.0000%	8,075	Page 336.7b
2	General Depreciation	123	100.0000% (a)	123	100.0000%	123	Page 336.9b
3	Total (line 1+2)			8,198		8,198	
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	40,635	100.0000% (c)	40,635	100.0000%	40,635	Page 262-263 FN.1-2
7	General Property Taxes	328	100.0000%	328	100.0000%	328	Page 262-263 FN.1-2
8	Total (line 6+7)	40,963		40,963		40,963	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	48,591		48,591	100.0000%	48,591	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	48,591		48,591		48,591	
	Transmission Administrative and General						
14	Administrative and General	84,319					Page 323.197b
15	*less Property Insurance (#924)*	*14,501*					*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)]	69,818	100.0000% (a)	69,818		69,818	
19	*PLUS Property Insurance alloc. using Plant Allocation*	*14,501*	100.0000% *(c)*	14,501		14,501	
20	*PLUS Regulatory Comm. Exp. (FERC Assessments)*	*0*	100.0000% *(c)*	0		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)]	*84,319*		*84,319*		*84,319*	
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.		VPPSA	FERC Form 1 Reference
	PTF Transmission Plant Allocation Factor		
1	PTF Transmission Investment	3,059,672	NEPOOL Catalog
2	Total Transmission Investment	3,059,672	Page 207.58g
3	Percent Allocation (Line 1/Line 2)	100.0000%	
	Transmission Wages and Salaries Allocation Factor		
4	Direct Transmission Wages and Salaries	19,391	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	19,391	
7	Total Wages and Salaries	19,391	Page 354.28b
8	Administrative and General Wages and Salaries	0	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)	19,391	
11	Percent Allocation (Line 6/Line 10)	100.0000%	
	Plant Allocation Factor		
12	Total Transmission Investment	3,059,672	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)*	3,059,672	
15	Total Plant in Service	3,059,672	Page 207.95g
16	Percent Allocation (Line 14 / Line 15)	100.0000%	

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 13, 2010	RTO ROE filing
Revenue Requirements for (year):	**Calendar Yr 2009** $ 13,575	
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 =	13,576	(a)	`	(f)	
Total of Attachment F - Section J - Support Revenue	0	(b)		(g)	N/A for Johnson
Total of Attachment F - Section K - Support Expense	0	(c)		(h)	N/A for Johnson
Total of Attachment F - Section (L through O)	(1)	(d)		(i)	N/A for Johnson
Sub Total - Sum (A through I) - J + K + (L through O)	13,575	(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:	13,575	(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)	13,575	(l)=(k)+(b)+(g)-(h)	

Village of Johnson
Annual Revenue Requirements of PTF Facilities
for costs in 2009

Shading denotes an input

Line N		Attachment F Reference Section:	Total	Reference	
	I. INVESTMENT BASE				
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)	70,210	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)		46,807		
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)	409	Worksheet 3, line 23 column 5	
13	Total Investment Base (Line 9+10+11+12)		47,216		

	II. REVENUE REQUIREMENTS				
14	Investment Return and Income Taxes	(A)	5,496	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)	1,882	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)	2,232	Worksheet 4, line 13 column 5	
21	Administrative & General Expense	(H)	1,041	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)		13,576		

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		1,586,650	100.01%	11.64%	11.64%	11.64%
TOTAL INVESTMENT RE	$	1,586,650	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 ` 47,216) x 0) / (1 - 0)

N/A for Johns

= 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) / 47,216) + 0.0000000)* 0 / (1 - 0)

= 0.0000000

(a)+(b)+(c) **Cost of Capit** = 0.1164000

		(PTF)	
INVESTMENT BASE	$	47,216	From Worksheet 1
x Cost of Capital Rate		0.1164000	
= Investment Return and Incom		5,496	To Worksheet 1

Shading denotes an input

	(1) Total	fo (2) Wage/Plant Allocation Factors	(3) = (1)*(2) Transmission Allocated	(4) PTF Allocation Factor (b)	(5) = (3)*(4) PTF Allocated	FERC Form 1 Reference for col (1)	
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	70,210		70,210	100.0000%	70,210	Page 219.25b	
General Plant Accum.Depreciation	0	0.0000% (a)	0	100.0000%	0	Page 219.28b	
Total (line 5+6)	70,210		70,210		70,210		
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					2,232	Worksheet 1, Line 20	
Administrative & General Expense					1,041	Worksheet 1, Line 21	
Transmission Support Expense					0	Worksheet 1, Line 24	(FROM
Subtotal (line 19+20+21)					3,273		
					0.125	x 45 / 360	
Total (line 22 * line 23)					409		

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

Shading denotes an input

Line No.		(1) Total	(2) 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	1,882	100.0000% (c)	1,882	100.0000%	1,882	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)	1,882		1,882		1,882	
	Transmission Operation and Maintenance						
9	Operation and Maintenance	2,232		2,232	100.0000%	2,232	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	2,232		2,232	`	2,232	
	Transmission Administrative and General						
14	Administrative and General	1,066					Page 323.197b
15	*less Property Insurance (#924)*	*1,041*					*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)]	25	0.0000% (a)	0	100.0000%	0	
19	*PLUS Property Insurance alloc. using Plant Allocation*	*1,041*	100.0000% *(c)*	1,041	100.0000%	1,041	
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)]	*1,066*		*1,041*		*1,041*	
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

Shading denotes an input for costs in 2008

Line No.		Johnson	FERC Form 1 Reference	
	PTF Transmission Plant Allocation Factor			
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	0	Page 354.21b	N/A for Johnson
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	0		
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	Includes Benn-Searsburg line
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	Includes Benn-Searsburg line
16	Percent Allocation (Line 14 / Line 15)	100.0000%		

Vermont Electric Cooperative, Inc.
2009 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	14,108	3,057	
2009 Vermont DPS Electric Utility Annual Report, Schedule E-3, line 66			17,165

2009 Highgate Transmission Facilities Revenues	**17,165**

Calculation of VEC's 2009 Highgate Transmission Facilities Revenue Requirements

Rental Fee = Recovery of Non-Project Manager Invoiced Costs, including	14,108	
(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	3,057	
(I) Integrated Facilities Charges		
less (J) Transmission Support Revenues	(17,165)	*
(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 2009 Highgate Transmission Facilities Revenue Requirements	**0**	

* Paid by Vermont Marble Power Division

Attachment 3

Summary of Forecasted Transmission Revenue Requirements Associated with Projected PTF Additions for 2010

Participating Transmission Owner	Total Estimated 2010 PTF Capital Costs ($)	Annual Carrying Charge (%)	Forecasted PTF Revenue Requirement ($)	6/1/10 RNS Rate Impact ($/kW-yr.)
VT Transco	203,150,000	16.98%	34,488,693	1.77250
CMP	204,479,343	16.49%	33,727,217	1.73337
NGRID	151,750,000	16.60%	25,197,392	1.29499
NU	134,384,000	17.46%	23,465,000	1.20596
BHE	33,000,000	17.55%	5,791,225	0.29763
NSTAR	32,910,000	13.63%	4,487,271	0.23062
UI	15,706,000	21.14%	3,320,051	0.17063
FPL-NED	2,491,000	16.38%	408,014	0.02097
HG&E	139,000	24.66%	34,283	0.00176
	778,009,343	16.83%	130,919,146	6.72843
2009 RTO-NE 12 -CP RNS Load:		19,457,606 kW		

Attachment 4

Annual True-up Summary

Regional True-up Summary

Participating Transmission Owner	RNS Rev Req's 2008 Test Year + 2009 Forecast (As Billed)	RNS Rev Req'ts 2009 Test Year (For True-up)	Difference (overcollection), undercollection	Interest on Difference	Annual True Up and Associated Interest	6/1/10 RNS Rate Impact ($/kW-yr.)
UI	78,608,853	96,758,280	18,149,427	606,670	18,756,097	0.96395
NU	494,664,025	506,353,996	11,689,971	390,749	12,080,720	0.62087
CMP	45,512,297	49,023,806	3,511,509	117,377	3,628,886	0.18650
BHE	27,853,047	29,522,086	1,669,040	55,790	1,724,830	0.08865
FPL-NED	8,891,153	8,979,249	88,096	2,899	90,995	0.00468
VT Transco	83,030,529	77,167,461	(5,863,068)	(195,982)	(6,059,050)	(0.31140)
NSTAR	153,640,560	146,997,256	(6,643,305)	(222,061)	(6,865,366)	(0.35284)
NGRID	198,851,206	188,226,489	(10,624,717)	(355,146)	(10,979,863)	(0.56430)
	$ 1,091,051,670	$ 1,103,028,623	$ 11,976,953	$ 400,296	$ 12,377,249	$ 0.63611
2009 RTO-NE 12-CP RNS Load:		19,457,606	kW			

Attachment 5

Schedule 1 Rates Effective June 1, 2010 – May 31, 2011
Based on 2009 Data

SUMMARY

ISO NE Transmission, Markets & Services Tariff
OATT Regional Schedule 1 - Scheduling System Control and Dispatch Service Rate
Effective June 1, 2010 - May 31, 2011
(Reflecting 2009 Schedule 1 Costs)

1	Total of FERC account 561-561.4 (exclude REMVEC & CONVEX costs)	$ 13,365,053	1
2	Less ISO & OATT Sch 1 costs included in above accounts	1,290,441	2
3	Sub-total(1-2)	12,074,612	3
4	Amount allocated to transmission function	12,074,612	4
5	Transmission related S&D costs from SCADA or other systems	6,786,449	5
6	Sub-total (4+5)	18,861,061	6
7	PTF allocation factors (see page 2 for details)	77.9966%	7
8	Sub-total after applying ptf allocation factors (from page 2)	14,710,983	8
9	Maine LCC costs	5,257,935	9
10	REMVEC II costs	1,611,972	10
11	CONVEX costs	11,957,945	11
12	Sub-total (9+10+11)	18,827,852	12
13	100% allocated to transmission function	18,827,852	13
14	Revenues credited for short-term Transmission Service	(1,341,006)	14
15	Total (8+13+14)	32,197,829	15
16	plus NEPOOL transmission related system & dispatch costs	-	16
17	Total transmission related system & dispatch revenue requirement (15+16)	$ 32,197,829	17
18	12 month CP LOAD (KW) as defined in section 46.1 of the ISO-NE Tariff	19,457,606	18
19	Long Term Firm PTP Capacity (KW)	-	19
20	Scheduling System Control and Dispatch Service Rate ($/KW YR): (17/(18+19))	$ 1.65477	20

ISO NE Transmission, Markets & Services Tariff
OATT Regional Schedule 1 - Scheduling System Control and Dispatch Service Rate
Effective June 1, 2010 - May 31, 2011
(Reflecting 2009 Schedule 1 Costs)

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15		16	
		Total of FERC acct 561 - 561.4 (exclude ME, REMVEC, CONVEX /ESCC costs)	Less Reg Sch 1 & ISO costs included in Column 1 accounts	Sub-total (1-2)	100% allocated to transmission function	Transmission related S&D costs from SCADA or other Local Control Centers	Sub-total (4+5)	PTF allocation factor	Sub-total (6x7)	Maine LCC - PTF RELATED SCH 1 REV REQ'TS.	REMVEC II costs	CONVEX/ESCC costs	Sub-total (9+10+11)	100% allocated to transmission function	Revenues credited for short term transmission service must be negative	TOTAL (8+13+14)		SCHEDULE 1 Revenue Allocation %	
1	NSTAR			-	-	6,786,449	6,786,449	87.8887%	5,964,522.00				-	-	(220,968)	5,743,554	1	17.8383%	NSTAR
2	BH	450,511		450,511	450,511		450,511	63.0369%	283,988.00	270,823			270,823	270,823	(42,975)	511,836	2	1.5897%	BH
3																			
4																			
5																			
6																			
7	CMP			-	-		-		-	4,822,685			4,822,685	4,822,685	(184,317)	4,638,368	7	14.4058%	CMP
7a	MEPCO			-	-		-		-	164,427			164,427	164,427	(7,694)	156,733	7a	0.4868%	MEPCO
8	Ashburham			-	-		-		-		527		527	527	(23)	504	8	0.0016%	Ashburham
9	Boylston			-	-		-		-		494		494	494	(21)	473	9	0.0015%	Boylston
10	Braintree			-	-		-		-		8,059		8,059	8,059	(342)	7,717	10	0.0240%	Braintree
11	Danvers			-	-		-		-		6,531		6,531	6,531	(277)	6,254	11	0.0194%	Danvers
12	FG&E	117,759	90,620	27,139	27,139		27,139	20.4716%	5,556		9,419		9,419	9,419	(707)	14,268	12	0.0443%	FG&E
13	Georgetown			-	-		-		-		693		693	693	(30)	663	13	0.0021%	Georgetown
14	Groton, MA			-	-		-		-		931		931	931	(40)	891	14	0.0028%	Groton, MA
15	Hingham			-	-		-		-		3,045		3,045	3,045	(130)	2,915	15	0.0091%	Hingham
16	Holden			-	-		-		-		1,876		1,876	1,876	(80)	1,796	16	0.0056%	Holden
17	Hudson			-	-		-		-		5,782		5,782	5,782	(246)	5,536	17	0.0172%	Hudson
18	Hull			-	-		-		-		863		863	863	(37)	826	18	0.0026%	Hull
19	Ipswich			-	-		-		-		1,940		1,940	1,940	(83)	1,857	19	0.0058%	Ipswich
20	Littleton, MA			-	-		-		-		4,249		4,249	4,249	(180)	4,069	20	0.0126%	Littleton, MA
21	Mansfield			-	-		-		-		4,248		4,248	4,248	(180)	4,068	21	0.0126%	Mansfield
22	Marblehead			-	-		-		-		2,063		2,063	2,063	(87)	1,976	22	0.0061%	Marblehead
23	Middleboro			-	-		-		-		2,556		2,556	2,556	(108)	2,448	23	0.0076%	Middleboro
24	Middleton			-	-		-		-		1,480		1,480	1,480	(63)	1,417	24	0.0044%	Middleton
25	N.Attleboro			-	-		-		-		4,254		4,254	4,254	(181)	4,073	25	0.0126%	N.Attleboro
26	Pascoag			-	-		-		-		451		451	451	(19)	432	26	0.0013%	Pascoag
27	Paxton			-	-		-		-		396		396	396	(17)	379	27	0.0012%	Paxton
28	Peabody			-	-		-		-		8,590		8,590	8,590	(365)	8,225	28	0.0255%	Peabody
29	Princeton			-	-		-		-		285		285	285	(8)	277	29	0.0009%	Princeton
30	Reading			-	-		-		-		8,478		8,478	8,478	(360)	8,118	30	0.0252%	Reading
31	Rowley			-	-		-		-		572		572	572	(25)	547	31	0.0017%	Rowley
32	Shrewsbury			-	-		-		-		5,720		5,720	5,720	(243)	5,477	32	0.0170%	Shrewsbury
33	Sterling			-	-		-		-		741		741	741	(31)	710	33	0.0022%	Sterling
34	Taunton			-	-		-		-		10,768		10,768	10,768	(458)	10,310	34	0.0320%	Taunton
35	Templeton			-	-		-		-		1,621		1,621	1,621	(69)	1,552	35	0.0048%	Templeton
36	Wakefield			-	-		-		-		3,408		3,408	3,408	(144)	3,264	36	0.0101%	Wakefield
37	W.Boylston			-	-		-		-		1,211		1,211	1,211	(51)	1,160	37	0.0036%	W.Boylston
38	NGRID 8,760,314			8,760,314	8,760,314		8,760,314	70.88%	6,209,311		1,510,721		1,510,721	1,510,721	(317,828)	7,402,204	38	22.9898%	NGRID
39	CL&P	56,090		56,090	56,090		56,090	90.62%	50,829			11,054,371	11,054,371	11,054,371	(446,643)	10,658,557	39	33.1033%	CL&P
40	PSNH	202,560		202,560	202,560		202,560	93.92%	190,244			897,897	897,897	897,897	(33,947)	1,054,194	40	3.2741%	PSNH
41	WMECO	41,584		41,584	41,584		41,584	90.08%	37,459			5,677	5,677	5,677	(3,959)	39,177	41	0.1217%	WMECO
42	NAEC			-	-		-		-				-	-		-	42	0.0000%	NAEC
43	HWP			-	-		-		-				-	-		-	43	0.0000%	HWP
44	HP&E			-	-		-		-				-	-		-	44	0.0000%	HP&E
45	Total submitted by NU	300,234	-	300,234	300,234		300,234		278,532			11,957,945	11,957,945	11,957,945	(484,549)	11,751,928	45	36.4991%	Total submitted by NU
46	Chicopee			-	-		-		-				-	-		-	46	0.0000%	Chicopee
47	CMEEC			-	-		-		-				-	-		-	47	0.0000%	CMEEC
48	Holyoke			-	-		-		-				-	-		-	48	0.0000%	Holyoke
49	S. Hadley			-	-		-		-				-	-		-	49	0.0000%	S. Hadley
50	Westfield Gas & Electric			-	-		-		-				-	-		-	50	0.0000%	Westfield Gas & Electric
51	UI	1,230,298	1,199,821	30,477	30,477		30,477	96.3395%	29,361				-	-	(7,628)	21,733	51	0.0675%	UI
52	VTransco	2,505,937		2,505,937	2,505,937		2,505,937	77.4047%	1,939,713				-	-	(70,442)	1,869,271	52	5.8056%	VTransco
53	TOTALS	$ 13,365,053	$ 1,290,441	$ 12,074,612	$ 12,074,612	$ 6,786,449	$ 18,861,061	77.9966%	$ 14,710,983	$ 5,257,935	$ 1,611,972	$ 11,957,945	$ 18,827,852	$ 18,827,852	$ (1,341,006)	$ 32,197,829	53	100%	TOTALS

ISO NE Transmission, Markets & Services Tariff OATT Regional Schedule 1 - Scheduling System Control and Dispatch Service Rate Effective June 1, 2010 - May 31, 2011 (Reflecting 2009 Schedule 1 Costs)		
COMPANY		**SCHEDULE 1 DISTRIBUTION %**
Ashburham		0.0016%
Bangor Hydro		1.5897%
NSTAR		17.8383%
Boylston		0.0015%
Braintree		0.0240%
Central Maine Power		14.4058%
MEPCO		0.4868%
Chicopee		0.0000%
Connecticut Municiple Electric Energy		0.0000%
Danvers		0.0194%
Fitchburg Gas & Electric		0.0443%
Georgetown		0.0021%
Groton, MA		0.0028%
Hingham		0.0091%
Holden		0.0056%
Holyoke		0.0000%
Hudson		0.0172%
Hull		0.0026%
Ipswich		0.0058%
Littleton, MA		0.0126%
Mansfield		0.0126%
Marblehead		0.0061%
Middleboro		0.0076%
Middleton		0.0044%
N.Attleboro		0.0126%
National Grid		22.9898%
Northeast Utilities		36.4991%
Pascoag		0.0013%
Paxton		0.0012%
Peabody		0.0255%
Princeton		0.0009%
Reading		0.0252%
Rowley		0.0017%
S. Hadley		0.0000%
Shrewsbury		0.0170%
Sterling		0.0022%
Taunton		0.0320%
Templeton		0.0048%
United Illuminating		0.0675%
VTransco		5.8056%
W. Boylston		0.0036%
Wakefield		0.0101%
Westfield Gas & Electric		0.0000%
	TOTAL =	**100.0000%**

Attachment 6

PTOs' Annual Revenue Requirement Calculations
Pursuant to Schedule 1 and based on 2009 Data

NSTAR Electric Company
Annual Schedule 1 Revenue Requirements - Dispatch Center
Cost Year: 2009
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	3,410,644	Sheet 3, Line 2(f)
4	Dispatch Center Plant Held for Future Use	A.1.c	-	Sheet 3, Line 3(f)
5	Total Plant		$ 14,681,395	Sum Lines 2 thru 4
6	Dispatch Center Related Depreciation Reserve	A.1.d	(4,541,051)	Sheet 3, Line 7(f)
7	Dispatch Center Related Accumulated Deferred Taxes	A.1.e	(2,847,102)	Sheet 3, Line 13(f)
8	Total Net Plant		$ 7,293,242	Sum Lines 5 thru 7
9	Other Regulatory Assets	A.1.f	123,382	Sheet 3, Line 18(f)
10	Dispatch Center Prepayments	A.1.g	130,558	Sheet 3, Line 20(f)
11	Disptach Center Materials & Supplies	A.1.h	5,407	Sheet 3, Line 21(f)
12	Dispatch Center Related Cash Working Capital	A.1.i	598,033	Sheet 3, Line 25(f)
13	**Total Dispatch Center Investment Base**		**$ 8,150,622**	Sum Lines 8 thru 12
14	**Revenue Requirements**			
15	Investment Return and Income Taxes	A.2	$ 1,100,902	Sheet 2, Line 38(c)
16	Disptach Center Depreciation Expense	B	470,732	Sheet 4, Line 4(f)
17	Dispatch Center Related Amortization of Investment Tax Credits	C	(4,026)	Sheet 4, Line 5(f)
18	Dispatch Center Related Municipal Tax Expense	D	235,246	Sheet 4, Line 6(f)
19	Dispatch Center Related Payroll Tax Expense	E	199,335	Sheet 4, Line 24(f)
20	Dispatch Center Operation & Maintenance Expense	F	2,648,225	Sheet 4, Line 13(f)
21	Dispatch Center Related Administrative and General Expenses	G	2,136,036	Sheet 4, Line 23(f)
22	Revenues Received from ISO		-	Sheet 5, Line 3(f)
23	**Total Revenue Requirements**		**$ 6,786,449**	Sum Lines 15 thru 22
24	PTF Transmission Plant Allocator		87.89%	RNS Sheet 6
25	**PTF Revenue Requirement for SCADA**		**$ 5,964,525**	Line 23 * Line 24

NSTAR Electric Company
Investment Return and Income Taxes
Cost Year: 2009
Sheet 2

Line	(a) Description	(b) Tariff Section	(c) Balance	(d) Capitalization Ratio	(e) Cost*	(f) Weighted Cost	(g) Equity Cost	(h) Reference
1	**Weighted Cost of Capital**	A.2.a						
2	Long Term Debt	A.2.a.i	1,439,472,003	40.2676%	5.56%	2.2387%		Page 112.24c
3	Preferred Stock	A.2.a.ii	43,000,000	1.2029%	4.56%	0.0548%	0.0548%	Page 112.3c
4	Common Equity	A.2.a.iii	2,092,293,592	58.5295%	11.64%	6.8128%	6.8128%	Page 112.16c (less Line 3)
5	Total		3,574,765,595	100.0000%		9.1064%	6.8677%	Sum Lines 2 thru 4
6	Total Investment Base		8,150,622					Sheet 1, Line 13(c)
7	Weighted Cost of Capital		9.1064%					Line 5, Col (f)
8	Total Return on Investment		$ 742,225					Line 6 * Line 7
9	**Federal Income Tax**	A.2.b						
10	A = Equity Cost		6.8677%					Line 5, Col (g)
11	B = Transmission Amortization of ITC		(4,026)					Sheet 4, Line 5(f)
12	C = Equity AFUDC		-					
13	Total B + C		(4,026)					Line 11 + Line 12
14	D = Investment Base		8,150,622					Line 6
15	(B + C) / D		-0.0494%					Line 13 / Line 14
16	(A + [(C + B) / D]		6.8183%					Line 10 + Line 15
17	FT = Federal Income Tax Rate		35.0000%					
18	1 - FT		65.0000%					1 - Line 17
19	Federal Tax Factor		3.6714%					Line 16 * Line 17 / Line 18
20	Total Federal Income Taxes		$ 299,240					Line 14 * Line 19
21	**State Income Tax**	A.2.c						
22	A = Equity Cost		6.8677%					Line 5, Col (g)
23	B = Transmission Amortization of ITC		(4,026)					Sheet 4, Line 5(f)
24	C = Equity AFUDC		-					
25	Total B + C		(4,026)					Line 23 + Line 24
26	D = Investment Base		8,150,622					Line 6
27	(B + C) / D		-0.0494%					Line 25 / Line 26
28	(A + [(C + B) / D]		6.8183%					Line 22 + Line 27
29	ST = State Income Tax Rate		6.5000%					
30	1 - ST		93.5000%					1 - Line 29
31	Federal Tax Factor		3.6714%					Line 22
32	State Tax Factor		0.7292%					(Line 28 + Line 31) * Line 29 / Line 30
33	Total State Income Taxes		$ 59,436					Line 26 * Line 32
34	**Investment Return and Income Taxes**	A.2						
35	Return on Investment		742,225					Line 8
36	Federal Income Taxes		299,240					Line 20
37	State Income Taxes		59,436					Line 33
38	**Total Investment Return and Income Taxes**		$ 1,100,902					Sum Lines 35 thru 37
39	**Value of 50BP ROE Adder**							
40	ROE Adder		0.5000%					Per Tariff
41	Equity Ratio		58.5295%					Line 4, Col (d)
42	Effective Adder		0.2926%					Line 40 * Line 41
43	Tax Gross-up		0.1889%					Line 19 * .645413
44	Adder plus Gross-up		0.4815%					Line 42 + Line 43
45	Rate Base		$ 8,150,622					Line 6
46	Earned Adder		$ 39,247					Line 44 * Line 45
47	PTF Ratio		87.89%					RNS Sheet 6
48	**PTF Related Adder**		$ 34,494					Line 46 * Line 47

NSTAR Electric Company
Dispatch Center Investment Base
Cost Year: 2009
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	179,657,600	W&S	1.8984%	3,410,644	Page 207.99g
3	**Dispatch Center Plant Held for Future Use**	A.1.c	-	Direct	100.0000%	-	FF1: Page 214.12 & 13(d)
4	**Dispatch Center Related Depreciation Reserve**	A.1.d					
5	Dispatch Center Depreciation Reserve		(3,413,803)	Direct	100.0000%	(3,413,803)	See supporting detail
6	Transmission Related General Depreciation Reserve		(59,378,446)	W&S	1.8984%	(1,127,248)	Page 219.28b
7	Total Dispatch Center Related Depreciation Reserve		(62,792,249)			(4,541,051)	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	0.2816%	-	Page 273.8k
10	Accumulated Deferred Income Taxes - Other Property (Acct #282)		(534,485,979)	Plant	0.2816%	(1,505,367)	Page 275.5k
11	Accumulated Deferred Income Taxes - Other (Acct #283)		(570,604,941)	Plant	0.2816%	(1,607,095)	Page 277.3k
12	Less Accumulated Deferred Income Taxes (Acct #190)		94,217,253	Plant	0.2816%	265,361	Page 234.2c
13	Total Dispatch Center Related Accumulated Deferred Taxes		(1,010,873,667)			(2,847,102)	Sum Lines 9 thru 12
14	**Other Regulatory Assets**	A.1.f					
15	FAS 106		2,319,775	W&S	1.8984%	44,039	Pgae 232.30f
16	FAS 109		35,405,874	Plant	0.2816%	99,720	Page 232.23f
17	FAS 109 Liability		(7,234,756)	Plant	0.2816%	(20,377)	Page 278.2f
18	Total Other Regulatory Assets		30,490,893			123,382	Sum Lines 15 thru 17
19	**Dispatch Center Prepayments**	A.1.g					
20	Prepayments		6,877,218	W&S	1.8984%	130,558	Page 111.57c
21	**Dispatch Center Materials and Supplies**	A.1.h	1,919,805	N/A	0.2816%	5,407	FF1: Page 227.8(c)+227.5(c) Trans
22	**Dispatch Center Related Cash Working Capital**	A.1.i					
23	Dispatch Center Operation and Maintenance Expense		2,648,225	WC	12.5000%	331,028	Sheet 4, Line 13(f)
24	Dispatch Center Related Administrative and General Expense		2,136,036	WC	12.5000%	267,004	Sheet 4, Line 23(f)
25	Total Dispatch Center Related Cash Working Capital		4,784,261			598,033	Line 23 + Line 24
26	(d) Account 282		540,039,665	FF1 pg 275, line 9, col k			
27	less amounts related to divestiture		(5,553,686)	FF1 pg 275, line 4, col k			
28	Total Account 282		534,485,979	Sum line 26 thru line 27			
29	(e) Account 283		682,796,457	FF1 pg 277, line 9, col k			
30	less amounts related to divestiture		(112,191,516)	FF1 pg 277, footnote			
31	Total Account 283		570,604,941	Sum line 29 thru line 30			

Notes:

Description	**Allocation Factor**	**Reference**
Direct Allocation (Direct)	100.0000%	
Wages & Salary Allocation (W&S)	1.8984%	Sheet 6, Line 6(c)
Plant Allocation Allocation (Plant)	0.2816%	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: 2009
Sheet 4

Line	(a) Description	(b) Tariff Section	(c) Total	(d) Allocator	(e) Allocation Factor	(f) Dispatch Center Allocated	(g) Reference
1	**Dispatch Center Depreciation Expense**	B					
2	Dispatch Center Depreciation		275,575	Direct	100.0000%	275,575	See Line 34
3	General Depreciation		10,280,007	W&S	1.8984%	195,157	Page 336.10f
4	Total Dispatch Center Depreciation Expense		10,555,582			470,732	Line 2 + Line 3
5	**Dispatch Center Related Amortization of Investment Tax Credits**	C	(1,429,600)	Plant	0.2816%	(4,026)	Page 266.8f + Page 266.13f
6	**Dispatch Center Related Municipal Tax Expense**	D	83,525,081	Plant	0.2816%	235,246	Page 263.10i
7	**Dispatch Center Operations & Maintenance Expense**	F					
8	Load dispatching		-	Direct	100.0000%	-	
9	Load dispatching - Reliability		1,066,884	Direct	100.0000%	1,066,884	Page 321.85 col.(b) footnote
10	Load dispatching - Mon & Oper Trans System		1,054,696	Direct	100.0000%	1,054,696	Page 321.86 col.(b) footnote
11	Load dispatching - Trans Service & Scheduling		526,645	Direct	100.0000%	526,645	Page 321.87 col.(b) footnote
12	Scheduling, System Control and Dispatch Services		8,994,051		0.0000%	-	Page 321.88 col.(b) footnote
13	Total Dispatch Center O&M Expense		11,642,276			2,648,225	Sum Lines 8 thru 12
14	**Dispatch Center Related Administrative & General Expenses**	G					
15	Administrative and General Expenses		121,074,096				Page 323.197b
16	less Property Insurance (Acct #924)		(585,497)				Page 323.185b
17	less Regulatory Commission Expenses (Acct #928)		(7,665,807)				Page 323.189b
18	less General Advertising Expenses (Acct #930.1)		(392,760)				Page 323.191b
19	Subtotal		112,430,032	W&S	1.8984%	2,134,387	Sum Lines 15 thru 18
20	Property Insurance		585,497	Plant	0.2816%	1,649	Page 323.185b
21	Transmission Related Regulatory Commission Expenses		-	Plant	0.2816%	-	
22	Transmission Related General Advertising Expense		-	Direct	100.0000%	-	
23	Total Dispatch Center Related A&G Expenses		113,015,529			2,136,036	Sum Lines 20 thru 22
24	**Dispatch Center Related Payroll Tax Expense**	E	10,500,069	W&S	1.8984%	199,335	Page 263.13i

25 **NOTES:**

Line	Description	Allocation Factor	Reference
26			
27	Direct Allocation (Direct)	100.0000%	
28	Wages & Salaries Allocation (W&S)	1.8984%	Sheet 6, Line 6(c)
29	Plant Allocation (Plant)	0.2816%	Sheet 6, Line 16(c)

Line	Description	Total Investment	Life Depr. Rate	Depreciation Expense	Reference
30					
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: 2009
Sheet 5

Line	(a) Description	(b) Tariff Section	(c) Total	(d) Allocator	(e) Allocation Factor	(f) Dispatch Center Allocated	(g) Reference
1	**Revenues received from ISO**	H					
2	NEPOOL Scheduling & Dispatch Revenue		220,968	Direct		220,968	OATT Schedule 1 TOUT
3	Total Revenues Received from ISO		220,968			220,968	

4 **NOTES:**

Line	Description	Allocation Factor	Reference
5			
6	Direct Allocation (Direct)	100.0000%	
7	Wages & Salaries Allocation (W&S)	1.8984%	Sheet 6, Line 6(c)
8	Plant Allocation (Plant)	0.2816%	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: 2009
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		2,306,393	Acct 561 Labor
3	NSTAR Electric Direct Wages & Salaries		158,899,548	Page 354.28b
4	Administrative & General Wages & Salaries		(37,408,971)	Page 354.27b
5	Total NSTAR Electric Wages & Salaries net of A&G		121,490,577	Line 3 + Line 4
6	**Wages & Salaries Allocation Factor**		**1.8984%**	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		3,410,644	Sheet 3, Line 2(f)
14	Total Dispatch Center Plant Investment		14,681,395	Line 12 + Line 13
15	Total Plant in Service		5,212,682,028	Page 207.104g
16	**Plant Allocation Factor**		**0.2816%**	Line 14 / Line 15

CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/09

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:	**6/1/2010**
Submitted on:	
Revenue Requirements for (year):	**Unadjusted Test Year ended 12/31/09**
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**

		2009 Revenue Requirements	
Total of Appendix A - Sections A through I	=	8,627,270	(a)
Total of Appendix A - Section J - Support Revenue		474,942	(b)
Total Annual Revenue Requirement		**$ 8,152,329**	(c)=(a)-(b)
Transmission Related Revenue Requirement		$ 8,152,329	(d)= (c)* Satellite Wages & Salaries Allocation Fa
PTF Related Revenue Requirement		$ 4,822,685	(e)= (d)* Satellite PTF Allocation Factor

CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/09

Line No.	II. INVESTMENT BASE	Formula Reference Section:		Reference
1	Local Control Center Plant	II (A)(1)(a)	$ 17,652,144	Worksheet 3, line 1 column 3
3	Plant Held For Future Use	II (A)(1)(b)	2,217	Worksheet 3, line 3 column 3
4	Total Plant (Lines 1+2+3)		17,654,361	
5	Accumulated Depreciation	II (A)(1)(c)	11,700,018	Worksheet 3, line 5 column 3
6	Accumulated Deferred Income Taxes	II (A)(1)(d)	2,939,849	Worksheet 3, line 10 column 3
7	Loss On Reacquired Debt	II (A)(1)(e)	47,671	Worksheet 3, line 12 column 3
8	Other Regulatory Asssets	II (A)(1)(f)	2,861,836	Worksheet 3, line 17 column 3
9	Net Investment (Line 4-5-6+7+8)		5,924,001	
11	Prepayments	II (A)(1)(g)	41,091	Worksheet 3, line 19 column 3
12	Materials & Supplies	II (A)(1)(h)	69,037	Worksheet 3, line 21 column 3
13	Cash Working Capital	II (A)(1)(i)	796,336	Worksheet 3, line 28 column 3
14	Total Investment Base (Line 9+11+12+13)		$ 6,830,465	

	II. REVENUE REQUIREMENTS			
15	Investment Return and Income Taxes	II (A)	$ 1,019,105	Worksheet 2, line 44
16	Depreciation Expense	II (B)	1,123,015	Worksheet 4, line 1 column 3
17	Amortization of Loss on Reacquired Debt	II (C)	7,591	Worksheet 4, line 3 column 3
18	Investment Tax Credit	II (D)	(7,767)	Worksheet 4, line 5 column 3
19	Municipal Taxes	II (E)	114,641	Worksheet 4, line 7 column 3
20	Payroll Taxes	II (F)	0	Worksheet 4, line 9 column 3
21	Operation & Maintenance Expense	II (G)	4,547,254	Worksheet 4, line 16 column 3
22	Administrative & General Expense	II (H)	1,823,431	Worksheet 4, line 22 column 3
24	Transmission Support Revenue	II (I)	(474,942)	FERC Acct. No. 454, CE 946,947, MP403000 & 403100
30	Total Revenue Requirements (Line 15 thru 29)		$ 8,152,329	
	Local Control Center Wages and Salaries Allocation Factor		100.00%	Worksheet 5, line 20
	Transmission Related Revenue Requirement		$ 8,152,329	
	Local Control Center PTF Allocation Factor		59.16%	Worksheet 5, line 29
	PTF Transmission Related Revenue Requirement		$ 4,822,686	

CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/09

Line		CAPITALIZATION 12/31/09	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION	
1	LONG-TERM DEBT	$ 462,700,000	35.044%	6.648%	2.330%		Worksheet 9, line 5
2	PREFERRED STOCK	13,571,300	1.028%	4.993%	0.051%	0.051%	Worksheet 9, line 6
3	COMMON EQUITY	844,058,753	63.928%	11.640%	7.441%	7.441%	Worksheet 9, line 7
4							
5	TOTAL INVESTMENT RETURN	$ 1,320,330,053	100.00%		9.822%	7.492%	
6							
7	New Inv Adder Calc.		63.928%		0.000%	0.000%	0.000% including FIT&SIT

8
9 **Cost of Capital Rate=**
10
11 (a) Weighted Cost of Capital = 0.0982
12
13–15 (b) Federal Income Tax = (R.O.E. + (Satellite Inv. Tax Credit -w/s 1 + Equity AFUDC w/s 10) / Satellite Inv. Base) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)
16
17–18 = (0.0749 +((7,767) + 1,190) / 6,830,465) x 0.35) / (1 - 0.35)
19
20 = 0.0398230
21
22–24 (c) State Income Tax = (R.O.E. + (Satellite Inv. (Tax Credit + Eq. AFUDC of Deprec. Exp.) / Satellite Inv. Base) + Federal Income Tax)* State Income Tax Rate / (1 - State Income Tax Rate)
25
26–27 = (0.0749 +((7,767) + 1,190) / 6,830,465) + 0.0398230)* 0.0893 / (1 - 0.0893)
28
29 = 0.0111569
30
31
32
33 (a)+(b)+(c) **Cost of Capital Rate** = 0.1491999
34
35
36
37

Line		**Satellite**	**post 2003 ptf (Incremental Return Calc)**	**Investment Return & Taxes including Incremental Return**	
38					
39					
40	INVESTMENT BASE	$ 6,830,465	0		
41					
42	x Cost of Capital Rate	0.1491999	0.0000000		
43					
44	= Investment Return and Income Taxes	1,019,105	0	1,019,105	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 12/31/09

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	17,652,144		17,652,144	Worksheet 6, c.(a) l.17
2					
3	Local Control Center Plant Held for Future Use	209,797	1.0568% (a)	2,217	Worksheet 11, line 1
4					
5	Local Control Center Accumulated Depreciation	(11,700,018)		(11,700,018)	Worksheet 6, c.(b) l.17
6					
7	Local Control Center Accumulated Deferred Taxes				
8	Accumulated Deferred Taxes (281-283)	(459,063,654)	1.0568% (a)	(4,851,385)	Worksheet 11, line 3
9	Accumulated Deferred Taxes (190)	180,879,673	1.0568% (a)	1,911,536	Worksheet 11, line 2
10	Total (line 8+9)	(278,183,981)		(2,939,849)	
11					
12	Unamortized loss on Reacquired Debt	4,510,860	1.0568% (a)	47,671	Page 111.65d
13					
14	Other Regulatory Assets				
15	FAS 106	15,677,963	4.4124% (b)	691,774	Page 232.1, line 31e
16	FAS 109	205,342,747	1.0568% (a)	2,170,062	Page 232.1, line 4e - Page 278 1e
17	Total (line 12+13)	221,020,710		2,861,836	
18					
19	Prepayments	3,888,271	1.0568% (a)	41,091	Page 111.57d
20					
21	Total Materials and Supplies	6,532,692	1.0568% (a)	69,037	Worksheet 11, line 4
22					
23	Cash Working Capital				
24	Operation & Maintenance Expense			4,547,254	Worksheet 1, Line 21
25	Administrative & General Expense			1,823,431	Worksheet 1, Line 22
26	Subtotal (line 18+19+20)			6,370,685	
27				0.125	x 45 / 360
28	Total (line 21 * line 22)			796,336	

(a) Worksheet 5, line 37
(b) Worksheet 5, line 11

CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/09

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	1,123,015			1,123,015	Worksheet 6, c.d, l. 17
2						
3	Amortization of Loss on Reacquired Debt	718,290	1.06%	(b)	7,591	Page 117.58c
4						
5	Amortization of Investment Tax Credits	(735,000)	1.06%	(b)	(7,767)	411.4 only See note for Page 2
6						
7	Local Control Center Property Taxes	10,847,922	1.06%	(b)	114,641	w/s 11, line 5
8						
9	Payroll Taxes (c)	-	4.41%	(a)	-	
10						
11	Operation and Maintenance					
12	System Control and Load Dispatch - #556	0				Page 321.77b
13	Load Dispatching - #561 - 561.4	4,547,254				Page 321.84b-88b
14	Load Dispatching - #581	0				Page 322.105b
15	Less expenses incurred under ISO Tariff	-				Worksheet 7, line 7 & FERC acct. 561.
16	O&M - line 12+13+14-15	4,547,254			4,547,254	
17						
18	Administrative and General					
19	A & G subject to Wage & Salaries Allocation Factor	41,255,126	4.41%	(a)	1,820,341	Worksheet 8, line 28
20	A & G subject to Plant Allocation Factor	292,411	1.06%	(b)	3,090	Worksheet 8, line 31
21	A & G directly assigned to Local Control Center	-	100%		-	Worksheet 8, lines 14& 17
22	A&G (lines 19+20+21)	41,547,537			1,823,431	

(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 12/31/09

Worksheet 5 of 11

Line No.			Sch. 1 Rate Worksheet or FERC Form 1 Reference
1			
2	**Wages and Salaries Allocation Factor**	2009	
3			
4	Total Local Control Center Direct Wages and Salaries	2,084,929	worksheet 7, c.(d),l.5
5			
6	Total Wages and Salaries	56,734,062	Page 354.25b
7	Administrative and General Wages and Salaries	9,483,001	Page 354.24b
8	Affiliated Company Wages and Salaries less A&G	-	
9	Total Wages and Salaries net of A&G (line 6-7)	47,251,061	
10			
11	Percent Allocation (lines 4 / 9)	**4.41%**	
12			
13			
14	**Local Control Center Wages and Salaries Allocation Factor**		
15			
16	Total Transmission Local Control Center Direct Wages and Salaries	2,084,929	worksheet 7, c.(d),l.2
17			
18	Total Local Control Center Direct Wages and Salaries	2,084,929	worksheet 5, l.4
19			
20	Percent Allocation (lines 16/18)	**100.00%**	
21			
22			
23	**Local Control Center PTF Allocation Factor**		
24			
25	Total Local Control Center PTF Direct Wages and Salaries	1,233,384	worksheet 7, c.(e),l.2
26			
27	Total Transmission Local Control Center Direct Wages and Salaries	2,084,929	worksheet 5, l.4
28			
29	Percent Allocation (line 25/27)	**59.16%**	
30			
31			
32	**Local Control Center Plant Allocation Factor**		
33			
34	Total Investment in Local Control Center Plant	17,652,144	worksheet 6, c.(a),l.17
35	Total Plant in Service	1,670,410,851	Page 207.88g
36			
37	Percent Allocation (lines 34/35)	**1.06%**	

CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/09

Worksheet 6 of 11

		/---------------12/31/09--------------		/	
1	PROPERTY DESCRIPTION	COST	RESERVE	2009 DEPRECIATION	ref
2		(a)	(b)	©	
3	FURNITURE & EQUIPMENT	266,008	124,178	10,450	plant acctg
4	STRUCTURE COSTS & MAP BOARDS	3,750,352	1,454,331	91,884	plant acctg
5	UPS	284,858	137,575	10,550	plant acctg
6	EMS SYSTEM	-	-	-	plant acctg
7	EMS HARDWARE	1,834,871	1,095,978	203,854	plant acctg
8	EMS SOFTWARE	7,900,188	7,364,597	676,571	plant acctg
9	EMS SOFTWARE				plant acctg
10	LMS	-	-	-	plant acctg
11	S/S & GEN STA. RTUs & SCADA	2,758,126	947,417	69,505	plant acctg
12	EBCC	-	-	-	plant acctg
13	COMMUNICATION EQUIPMENT	815,265	545,908	59,677	plant acctg
14	PC EQUIPMENT	42,476	30,034	524	plant acctg
15					
16					
17	TOTALS	17,652,144	11,700,018	1,123,015	

CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/09

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	556-System Control and Load Dispatching	$ -	$ -	$ -		
2	561-Load Dispatching	4,547,254	2,462,325	2,084,929	1,233,384	851,545
3	581-Load Dispatching	-	-	-		
4						
5	TOTAL	$ 4,547,254	$ 2,462,325	$ 2,084,929		
6						

CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/09

Worksheet 8 of 11

	Acc't	Description	Amount	
1	920	Administrative and General Salaries	8,970,419	
2	921	Office Supplies and Expenses	2,185,552	
3	922	Less Administrative Expenses Transferred	(610,667)	
4	923	Outside Services	16,856,767	
5	924	Property Insurance	292,411	
6	925	Injuries and Damages	2,752,571	
7	926	Employee Pensions and Benefits	(1,337,609)	
8	928	Regulatory Commissions Expense	5,362,384	
9	930.1	General Advertising	924,630	
10	930.2	Miscellaneous General Expense	9,701,986	
11	931	Rents	738,055	
12	935	Maintenance of General Plant	1,998,052	
13		Total Admin & Gen'l Exp.	47,834,551	Page 323.168b
14		FERC assessments - Transmission (directly assigned)	1,484,660	
15		FERC assessments - Satellite (directly assigned)	-	to worksheet 4, line 21
16		FERC assessments - subject to plant allocation factor	-	FF1 page 350.c
17		TOTAL FERC ASSESSMENTS (14+15)	1,484,660	FF1 page 350.c
18		State assessments - Satellite (directly assigned)	-	to worksheet 4, line 21
19		Total State Assessments	3,877,724	FF1 page 350.c
	928	Total Regulatory Commissions Expense: (16+18) & from line 8	5,362,384	FF1 page 350.c
20				
21		General Advertising - Transmission related	-	
22		Non-Satellite related General Advertising Exp.	924,630	
	930.1	Total General Advertising Exp. (line 9)	924,630	
23		**Summary of Schedule 1 Treatment of A&G**		
24		Total A&G (line 13)	47,834,551	
25	924	less Property Insurance (line 5)	(292,411)	
26	928	less Regulatory Commissions Exp. (line 19)	(5,362,384)	
27	930.1	less Non-Trans. General Advertising Exp. (line 9)	(924,630)	
28	920-935	less EPRI Expenses	-	
		A&G subject to Wages and Salaries Allocation Factor:	41,255,126	to ws 4, line 19, col. 1
29				
30		Property Insurance (line 5)	292,411	
31		Regulatory Commissions Exp. - FERC assessments (line 15)	-	
		Total A&G subject to Plant Allocation Factor	292,411	to ws 4, line 20, col. 1

CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/09

			CAPITALIZATION 12/31/09	CAPITALIZATION RATIOS	COST OF CAPITAL	ANNUAL INTEREST	COST OF CAPITAL	EQUITY PORTION
1	MED-TERM NOTES	page 123.5	443,200,000	33.567%	6.697%	29,681,422		
2	POLLUTION CONTROL NOTES	page 123.5	19,500,000	1.477%	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	35.044%	6.648%	30,772,318	2.330%	
6	PREFERRED STOCK	page 123.6 and page 112.3d	13,571,300	1.028%	4.993%		0.051%	0.051%
7	COMMON EQUITY	page 112.14d less line 3d	844,058,753	63.928%	11.640%		7.441%	7.441%
8								
9	TOTAL INVESTMENT RETURN		1,320,330,053	100.00%			9.822%	7.492%
10								
11								
12	Capitalization excludes short term debt(i.e. Revolving Credit Agreement)							
13								

CENTRAL MAINE POWER COMPANY
LOCAL CONTROL CENTER REVENUE REQUIREMENTS
FOR THE TEST YEAR ENDED 12/31/09

	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%	
40	totals	430,621,754	7,369,650	**1.71%**	
41					
42	Transmission Plant related Depreciation Expense:			$ 69,505	From Worksheet 6, line 9
43					
44	AFUDC Adjustment			**1,190**	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 12/31/09

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	17,724,380	17,514,583	209,797	w/s 3, line 3
	Accumulated Deferred Income Taxes:						
2		190	Page 111.66d	211,812,302	30,932,629	180,879,673	w/s 3, line 9
		282		(317,782,028)	44,834,131	(272,947,897)	
		283		(210,331,271)	24,215,514	(186,115,757)	
3	subtotal 281-283		Page 113.53d	(528,113,299)	69,049,645	(459,063,654)	w/s 3, line 8
4	Materials & Supplies		Page 227.11c	9,451,246	2,918,554	6,532,692	w/s 3, line 21
5	Property Taxes		Page 263 21 i	15,137,868	4,289,946	10,847,922	w/s 4, line 7
	Total 190			211,812,302			
	Less ADIT- Def'd Gain on Generation Asset Sale			-			
	Difference			211,812,302			

Attachment 7

Service List of State Regulators and Other Interested Parties

CT Dept of Public Utility Control
10 Franklin Square
New Britain, CT 06051-2605

Maine Public Utilities Commission
State House, Station 18
242 State Street
Augusta, ME 04333-0018

MA Dept of Telecommunications and Energy
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
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Warwick, RI 02888

Vermont Public Service Board
112 State Street, Drawer 20
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Gordon Van Welie
ISO New England, Inc.
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Holyoke, MA 01040-2841

New England Power Pool
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Day Pitney LLP
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Power Planning Committee
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Anne C. George, President
NE Conference of Public Utilities Commissioners, Inc.
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Attachment 8

Service List of Participating Transmission Owners

Service List of
Participating Transmission Owners

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