NSTAR ELECTRIC GAS
Legal Department, 17th Floor
800 Boylston Street. Boston. Massachusetts 02199

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May 1, 2002

Mary L. Cottrell, Secretary
Department of Telecommunications & Energy
One South Station, 2nd Floor
Boston, Massachusetts 02110

Re: Cambridge Electric Light Company/ Commonwealth Electric Company
D.T.E. 00-83

Dear Madam Secretary:

Cambridge Electric Light Company and Commonwealth Electric Company (the "Companies") are pleased to supply their responses to the Settlement Questions listed on the attached sheet.

Sincerely,

John Cope-Flanagan

John Cope-Flanagan

Enclosures

cc: Caroline M. O'Brien, Hearing Officer
Jeffrey Hall, Rates and Revenue Requirements Division (7 copies)
Joseph Rogers, Assistant Attorney General
Robert N. Werlin, Esq.
Service List D.T.E. 00-83

Settlement Question Responses

DTE-SIS-2
DTE-SIS-4
DTE-SIS-5
DTE-SIS-8

May 1, 2002

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Cambridge Electric Light Company Commonwealth Electric Company	))))	D.T.E. 00-83

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing responses to information requests in accordance with Department rules.

John Cope-Flanagan

John Cope-Flanagan
Attorney for
NSTAR Electric & Gas Corporation
800 Boylston St., Floor 17
Boston, MA 02199

DATED: May 1, 2002

Information Request DTE-SIS-2

Please refer to the Settlement Agreement at 3, & b and to COM-BKR-1 (Settlement) at 4, Col. K. Please provide workpapers that show how the $4.431 million credit nets to the figures shown in Col. K. Also, provide a description of the adjustment.

Response

Please see below.

$ in Millions

Filed	Exhibit	Page No.	Column	Year	Amount	Reference
Jul-01	D.T.E. 00-83 (Supp 2)	4	K	2000	$ 2.530	(A)
	Pilgrim Provisional Decommissioning Trust Refund from Boston Edison				(4.431)	(B)
Apr-02	D.T.E. 00-83 (Settlement)	4	K	2000	$ (1.901)	

(A) Commonwealth's share of NCIO paid by Boston Edison to Entergy
(B) Commonwealth's share of Pilgrim Provisional Decommissioning Trust Refund received by Boston Edison

Information Request DTE-SIS-4

Please refer to Exhs. CAM-BKR-1 (Settlement) at 4, Col. D and CAM-BKR-1 (Supp. 2) at 4, Col. D. Please explain the $1.749 million difference between these schedules in Col. D.

Response

The $1.749 million difference between Exhibits CAM-BKR-1 (Settlement) at 4, Col. D and CAM-BKR-1 (Supp 2) at 4, Col. D reflects the reclassification of costs between Standard Offer/Default Service and Transition Charge resulting from a revised methodology of calculating the 1998 Standard Offer and Default Service Deferrals agreed upon in this Settlement Agreement.

In D.T.E. 99-90-C, the Department rejected Cambridge's method of calculating its deferral balances and required the Company to recover Standard Offer Service and Default Service deferrals consistent with precedent. Order at 78. Cambridge complied with this order, in the Second Supplemental (Supp 2) filing, by transferring $4.101 million from the Transition Charge Deferral to the Standard Offer Deferral effective December 31, 1998. That amount was calculated by multiplying the Standard Offer sales for 1998 by the 4 mill differential, which reflected the difference between the rate per kWh charged to customers (2.8 cents) and the approved wholesale cost of Standard Offer Service and Default Service rate per kWh (3.2 cents) for 1998. Interest of $0.100 million was included in the Standard Offer Deferral to equal the balance, as of December 31, 1998, of $4.201 million shown in the beginning balance of Exhibit CAM-RAP-1 (Supp 2).

This Settlement Agreement recalculates the Standard Offer Deferral and Default Service Deferral for 1998 in a manner similar to the calculation of those deferrals in 1999 and 2000. This resulted in a revision of the Standard Offer Deferral balance on December 31, 1998 (including interest) from $4.201 million to $2.580 million and the Default Service Deferral balance on December 31, 1998 (including interest) from $0 to ($0.138) million. The net difference of $1.759 million reduced by $0.010 million of interest ($1.749 million) is transferred to the Transition Charge Deferral by decreasing the Power Contract Obligation Market Value (Exhibit CAM-BKR-1 (Settlement) at 4, Col. D). Please see Attachment DTE-SIS-4 for the revised Cambridge Standard Offer and Default Services Deferral balances as of December 31, 1998.

Cambridge Electric Light Company
1998 Standard Offer & Default Service Deferral Estimate
$ in 000's

Line #	Description		Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Total
1	NUG Purchases (MWH)														
2	Seabrook 1		-	-	6,061	5,860	6,070	1,964	3,932	6,071	5,873	6,070	3,306	5,519	50,726
3	Altresco		-	-	19,705	19,015	18,431	18,030	18,175	18,434	14,959	19,663	19,588	19,973	185,973
4	Vermont Yankee		-	-	4,794	-	-	5,430	8,586	8,409	8,243	6,697	8,552	8,841	59,552
5	NUGs Generation		-	-	30,560	24,875	24,501	25,424	30,693	32,914	29,075	32,430	31,446	34,333	296,251
6	Less: Assumed Line Losses @	1.99%	-	-	(608)	(495)	(488)	(506)	(611)	(655)	(579)	(645)	(626)	(683)	(5,896)
7	Net MWH Delivered		-	-	29,952	24,380	24,013	24,918	30,082	32,259	28,496	31,785	30,820	33,650	290,355
8	DistCo. Settlement Price (cents per kWh)		$ -	$ -	$ 0.032	$ 0.032	$ 0.032	$ 0.032	$ 0.032	$ 0.032	$ 0.032	$ 0.032	$ 0.032	$ 0.032	
9	Cost of NUG Purchases		$ -	$ -	$ 958	$ 780	$ 768	$ 797	$ 963	$ 1,032	$ 912	$ 1,017	$ 986	$ 1,077	$ 9,290
10															
11	Fossil Generation														
12	Canal 1		-	-	13,766	5,441	3,416	15,862	15,583	9,261	14,412	13,356	15,410	18,976	125,483
13	Canal 2		-	-	21,914	22,096	27,645	21,524	25,125	25,938	21,223	26,858	19,198	35,644	247,165
14	Blackstone		-	-	79	-	-	474	390	453	189	-	-	269	1,854
15	Kendall		-	-	8,723	7,314	8,233	7,892	9,093	8,486	7,428	7,131	7,042	9,074	80,416
16	Kendall Jets		-	-	1	134	27	266	231	95	130	78	34	128	1,124
17	Total Fossil		-	-	44,483	34,985	39,321	46,018	50,422	44,233	43,382	47,423	41,684	64,091	456,042
18	Less: Assumed Line Losses @	1.99%	-	-	(885)	(696)	(782)	(916)	(1,003)	(880)	(863)	(944)	(830)	(1,275)	(9,074)
19	Net MWH Delivered		-	-	43,598	34,289	38,539	45,102	49,419	43,353	42,519	46,479	40,854	62,816	446,968
20	DistCo. Settlement Price (cents per kWh)		$ -	$ -	$ 0.032	$ 0.032	$ 0.032	$ 0.032	$ 0.032	$ 0.032	$ 0.032	$ 0.032	$ 0.032	$ 0.032	
21	Cost of Fossil Purchases		$ -	$ -	$ 1,395	$ 1,097	$ 1,233	$ 1,443	$ 1,581	$ 1,387	$ 1,361	$ 1,487	$ 1,307	$ 2,010	$ 14,301
22															
23	Short Term Purchases														
24	Enron		-	-	-	-	-	-	109	14	-	26	10	-	159
25	United Illuminating		-	-	16	202	-	-	166	110	-	-	-	-	494
26	Central Vermont Public Service		-	-	-	-	-	-	-	36	24	-	134	16	210
27	Northeast Utilities		-	-	-	-	-	-	71	253	346	-	162	81	913
28	New England Power		-	-	-	-	57	96	(17)	-	-	-	-	-	136
29	NEPEX		-	-	1,265	1,490	1,276	1,363	1,478	1,177	1,111	1,148	1,027	725	12,060
30	Vacant		-	-	-	-	-	-	-	-	-	-	-	-	-
31	Cost of Short Term Purchases		-	-	1,281	1,692	1,333	1,459	1,807	1,590	1,481	1,174	1,333	822	13,972
32															
33	Wholesale Cost Credit		-	-	(436)	(238)	(223)	(239)	(335)	(285)	(223)	(241)	(243)	(308)	(2,771)
34															
35	Total Cost of SO/DS Power		$ -	$ -	$ 3,198	$ 3,331	$ 3,111	$ 3,460	$ 4,016	$ 3,724	$ 3,531	$ 3,437	$ 3,383	$ 3,601	$ 34,792
36															
37	Revenues														
38	Sales for Resale		-	-	629	165	(162)	190	79	97	246	192	501	177	2,114
39	Standard Offer		-	-	1,708	2,812	2,901	3,149	3,091	3,271	3,254	2,859	2,979	2,690	28,714
40	Default Service		-	-	3	12	29	82	166	214	260	253	262	331	1,612

Cambridge Electric Light Company
1998 Standard Offer & Default Service Deferral Estimate
$ in 000's

Line #	Description	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Total
41	Total Revenues	-	-	2,340	2,989	2,768	3,421	3,336	3,582	3,760	3,304	3,742	3,198	32,440
42														
43	Total Deferral	-	-	858	342	343	39	680	142	(229)	133	(359)	403	2,352
44														
45	MWH Sales - Retail													
46	Standard Offer	-	-	61,012	100,420	103,626	112,487	110,398	116,820	116,211	102,113	106,379	96,090	1,025,556
47	Default Service	-	-	80	388	909	2,552	5,183	6,694	8,118	7,918	8,186	10,338	50,366
48	Total MWH Sales - Retail	-	-	61,092	100,808	104,535	115,039	115,581	123,514	124,329	110,031	114,565	106,428	1,075,922
49	Wholesale Sales - Belmont	-	-	8,325	7,211	7,477	7,942	9,629	9,474	7,869	7,701	8,242	9,114	82,984
50	Total MWH Sales	-	-	69,417	108,019	112,012	122,981	125,210	132,988	132,198	117,732	122,807	115,542	1,158,906
51														
52														
53	MWH Sales (Retail) Ratio													
54	Standard Offer	-	-	99.87%	99.62%	99.13%	97.78%	95.52%	94.58%	93.47%	92.80%	92.85%	90.29%	95.32%
55	Default Service	-	-	0.13%	0.38%	0.87%	2.22%	4.48%	5.42%	6.53%	7.20%	7.15%	9.71%	4.68%
56														
57	Wholesale Ratio	-	-	11.99%	6.68%	6.68%	6.46%	7.69%	7.12%	5.95%	6.54%	6.71%	7.89%	7.16%
58														
59	Standard Offer Deferral													
60	Cost of Power	-	-	3,194	3,318	3,084	3,383	3,836	3,522	3,300	3,190	3,141	3,251	33,219
61	Sales for Resale	-	-	(628)	(164)	161	(186)	(75)	(92)	(230)	(178)	(465)	(160)	(2,017)
62	Standard Offer Revenues	-	-	(1,708)	(2,812)	(2,901)	(3,149)	(3,091)	(3,271)	(3,254)	(2,859)	(2,979)	(2,690)	(28,714)
63	Standard Offer Deferral	-	-	858	342	344	48	670	159	(184)	153	(303)	401	2,488
64	Interest	-	-	2	5	7	8	10	12	12	12	12	12	92
65	YTD Standard Offer Deferral	-	-	860	1,207	1,558	1,614	2,294	2,465	2,293	2,458	2,167	2,580	2,580
66	December 31, 1998 Standard Offer Balance per Filing (4 mill Differential)													4,201
67	December 31, 1998 Standard Offer Balance Adjustment													(1,621)
68														
69	Default Service Deferral													
70	Cost of Power	-	-	4	13	27	77	180	202	231	247	242	350	1,573
71	Sales for Resale	-	-	(1)	(1)	1	(4)	(4)	(5)	(16)	(14)	(36)	(17)	(97)
72	Default Service Revenues	-	-	(3)	(12)	(29)	(82)	(166)	(214)	(260)	(253)	(262)	(331)	(1,612)
73	Default Service Deferral	-	-	-	-	(1)	(9)	10	(17)	(45)	(20)	(56)	2	(136)
74	Interest	-	-	-	-	-	-	-	-	-	-	(1)	(1)	(2)
75	YTD Default Service Deferral	-	-	-	-	(1)	(10)	-	(17)	(62)	(82)	(139)	(138)	(138)
76	December 31, 1998 Default Service Balance per Filing													-
77	December 31, 1998 Default Service Balance Adjustment													(138)

Information Request DTE-SIS-5

Please refer to Exhs. COM-BKR-1 (Settlement) at 4, Col. D and COM-BKR-1 (Supp. 2) at 4, Col. D. Please explain the $17.122 million difference between these schedules in Col. D.

Response

The $17.122 million difference between Exhibits COM-BKR-1 (Settlement) at 4, Col. D and COM-BKR-1 (Supp 2) at 4, Col. D reflects the reclassification of costs between Standard Offer/Default Service and Transition Charge resulting from a revised methodology of calculating the 1998 Standard Offer and Default Service Deferrals agreed upon in this Settlement Agreement.

In D.T.E. 99-90-C, the Department rejected Commonwealth's method of calculating its deferral balances and required the Company to recover Standard Offer Service and Default Service deferrals consistent with precedent. Order at 78. Commonwealth complied with this order, in the Second Supplemental (Supp 2) filing, by transferring $11.052 million from the Transition Charge Deferral to the Standard Offer Deferral effective December 31, 1998. That amount was calculated by multiplying the Standard Offer sales for 1998 by the 4 mill differential, which reflected the difference between the rate per kWh charged to customers (2.8 cents) and the approved wholesale cost of Standard Offer Service and Default Service rate per kWh (3.2 cents) for 1998. Interest of $0.268 million was included in the Standard Offer Deferral to equal the balance, as of December 31, 1998, of $11.320 million shown in the beginning balance of Exhibit COM-RAP-1 (Supp 2).

This Settlement Agreement recalculates the Standard Offer Deferral and Default Service Deferral for 1998 in a manner similar to the calculation of those deferrals in 1999 and 2000. This resulted in a revision of the Standard Offer Deferral balance on December 31, 1998 (including interest) from $11.320 million to $28.578 million and the Default Service Deferral balance on December 31, 1998 (including interest) from $0 to $0.362 million. The net difference of $17.620 million reduced by $0.498 million of interest ($17.122 million) is transferred from the Transition Charge Deferral by increasing the Power Contract Obligation Market Value (Exhibit COM-BKR-1 (Settlement) at 4, Col. D). Please see Attachment DTE-SIS-5 for the revised Commonwealth Standard Offer and Default Services Deferral balances as of December 31, 1998.

Commonwealth Electric Company
1998 Standard Offer & Default Service Deferral Estimate
$ in 000's

Line #	Description		Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Total
1	NUG Purchases (MWH)														
2	Seabrook 1		-	-	24,336	23,527	24,370	7,885	15,786	24,373	23,580	24,371	13,275	22,157	203,660
3	Pilgrim 1		-	-	54,532	51,497	50,732	52,757	52,385	50,982	49,483	54,571	52,863	53,827	523,629
4	Pioneer Hydro		-	-	967	-	-	-	-	-	-	-	-	-	967
5	Chicopee Hydro		-	-	1,464	1,331	1,156	726	421	223	551	101	370	351	6,694
6	Collins Hydro		-	-	816	755	630	607	402	107	102	216	183	181	3,999
7	Boott Mills Hydro		-	-	14,191	12,910	11,328	10,285	9,324	3,858	2,621	5,981	6,380	6,593	83,471
8	SEMASS		-	-	50,252	51,452	47,327	43,156	48,926	48,407	47,488	24,652	62,408	45,777	469,845
9	Northeast Energy		-	-	36,536	34,594	7,336	31,440	32,079	32,591	32,383	34,869	35,359	31,077	308,264
10	Dartmouth Power		-	-	-	47,996	50,034	47,569	47,250	46,560	46,764	50,222	40,596	49,745	426,736
11	MASSPOWER		-	-	26,551	29,721	36,596	34,184	36,147	36,902	32,946	16,820	37,699	39,730	327,296
12	Altresco		-	-	19,705	19,015	18,431	18,031	18,176	18,434	14,959	19,662	19,588	19,973	185,974
13	Lowell		-	-	-	-	-	-	-	-	-	-	-	-	-
14	NUGs Generation		-	-	229,350	272,798	247,940	246,640	260,896	262,437	250,877	231,465	268,721	269,411	2,540,535
15	Less: Assumed Line Losses @	6.79%	-	-	(15,573)	(18,523)	(16,835)	(16,747)	(17,715)	(17,819)	(17,035)	(15,716)	(18,246)	(18,293)	(172,502)
16	Net MWH Delivered		-	-	213,777	254,275	231,105	229,893	243,181	244,618	233,842	215,749	250,475	251,118	2,368,033
17	DistCo. Settlement Price (cents per kWh)		$ -	$ -	$ 0.032	$ 0.032	$ 0.032	$ 0.032	$ 0.032	$ 0.032	$ 0.032	$ 0.032	$ 0.032	$ 0.032	
18	Cost of NUG Purchases		$ -	$ -	$ 6,841	$ 8,137	$ 7,395	$ 7,357	$ 7,782	$ 7,828	$ 7,483	$ 6,904	$ 8,015	$ 8,036	$ 75,778
19															
20	Fossil Generation														
21	Canal 1		-	-	55,270	21,846	13,718	63,686	62,568	37,183	57,865	53,626	61,871	76,192	503,825
22	Canal 2		-	-	87,988	88,716	110,995	86,419	100,877	104,141	85,212	107,836	77,081	143,112	992,377
23	M. V. Diesels		-	-	5	13	11	11	19	138	137	137	257	257	985
24	Wyman 4		-	-	52	488	2,216	1,683	2,967	2,131	70	795	1,602	1,522	13,526
25	vacant		-	-	-	-	-	-	-	-	-	-	-	-	-
26	Total Fossil		-	-	143,315	111,063	126,940	151,799	166,431	143,593	143,284	162,394	140,811	221,083	1,510,713
27	Less: Assumed Line Losses @	6.79%	-	-	(9,731)	(7,541)	(8,619)	(10,307)	(11,301)	(9,750)	(9,729)	(11,027)	(9,561)	(15,012)	(102,578)
28	Net MWH Delivered		-	-	133,584	103,522	118,321	141,492	155,130	133,843	133,555	151,367	131,250	206,071	1,408,135
29	DistCo. Settlement Price (cents per kWh)		$ -	$ -	$ 0.032	$ 0.032	$ 0.032	$ 0.032	$ 0.032	$ 0.032	$ 0.032	$ 0.032	$ 0.032	$ 0.032	
30	Cost of Fossil Purchases		$ -	$ -	$ 4,275	$ 3,313	$ 3,786	$ 4,528	$ 4,964	$ 4,283	$ 4,274	$ 4,844	$ 4,200	$ 6,594	$ 45,061
31															
32	Short Term Purchases														
33	Enron		-	-	196	37	-	-	494	207	-	36	72	-	1,042
34	Enserch Energy		-	-	-	-	-	-	5	-	-	-	-	-	5
35	Duke Energy		-	-	1,368	46	-	-	-	-	-	-	154	-	1,568
36	United Illuminating		-	-	186	-	-	-	61	(9)	-	-	-	-	238
37	US Gen/PG&E		-	-	-	-	-	-	-	-	-	-	18	9	27
38	Central Vermont Public Service		-	-	-	-	-	-	50	4	16	77	(8)	19	158
39	Green Mountain Power		-	-	-	-	-	-	93	261	(33)	(1)	-	-	320
40	Central Maine Power		-	-	-	-	-	-	-	226	12	9	125	10	382
41	Northeast Utilities		-	-	-	-	-	-	-	32	47	108	(52)	104	239
42	Great Bay Power		-	-	-	-	-	-	-	3	9	-	-	-	12
43	Boston Edison		-	-	-	-	-	-	-	67	46	-	60	-	173
44	New England Power		-	-	89	93	48	(2)	162	408	2	-	-	-	800
45	NEPEX		-	-	673	520	(73)	606	627	873	1,020	442	123	149	4,960

Commonwealth Electric Company
1998 Standard Offer & Default Service Deferral Estimate
$ in 000's

Line #	Description	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98	Total
46	Eastern Energy	-	-	1	1	1	1	1	1	1	1	1	1	10
47	Small Power Producers	-	-	1	1	1	1	1	-	-	-	-	1	6
48	Cost of Short Term Purchases	-	-	2,514	698	(23)	606	1,494	2,073	1,120	672	493	293	9,940
49														
50	Total Cost of SO/DS Power	$ -	$ -	$ 13,630	$ 12,148	$ 11,158	$ 12,491	$ 14,240	$ 14,184	$ 12,877	$ 12,420	$ 12,708	$ 14,923	$ 130,779
51														
52	Revenues													
53	Sales for Resale	-	-	2,856	2,205	2,036	2,470	2,083	1,473	1,994	2,441	2,689	2,822	23,069
54	Standard Offer	-	-	4,981	7,578	7,514	7,263	8,757	9,093	9,027	7,568	7,475	7,957	77,213
55	Default Service	-	-	8	36	74	130	254	304	344	332	377	464	2,323
56	Total Revenues	-	-	7,845	9,819	9,624	9,863	11,094	10,870	11,365	10,341	10,541	11,243	102,605
57														
58	Total Deferral	-	-	5,785	2,329	1,534	2,628	3,146	3,314	1,512	2,079	2,167	3,680	28,174
59														
60	MWH Sales													
61	Standard Offer	-	-	177,922	271,364	269,067	259,945	313,462	325,345	323,061	270,870	267,607	284,807	2,763,450
62	Default Service	-	-	252	1,138	2,323	4,057	7,944	9,511	10,763	10,368	11,776	14,508	72,640
63	Total MWH Sales	-	-	178,174	272,502	271,390	264,002	321,406	334,856	333,824	281,238	279,383	299,315	2,836,090
64														
65	MWH Sales Ratio													
66	Standard Offer	-	-	99.86%	99.58%	99.14%	98.46%	97.53%	97.16%	96.78%	96.31%	95.78%	95.15%	97.44%
67	Default Service	-	-	0.14%	0.42%	0.86%	1.54%	2.47%	2.84%	3.22%	3.69%	4.22%	4.85%	2.56%
68														
69	Standard Offer Deferral													
70	Cost of Power	-	-	13,611	12,097	11,062	12,299	13,888	13,781	12,462	11,962	12,172	14,199	127,533
71	Sales for Resale	-	-	(2,852)	(2,196)	(2,018)	(2,432)	(2,032)	(1,431)	(1,930)	(2,351)	(2,576)	(2,685)	(22,503)
72	Standard Offer Revenues	-	-	(4,981)	(7,578)	(7,514)	(7,263)	(8,757)	(9,093)	(9,027)	(7,568)	(7,475)	(7,957)	(77,213)
73	Standard Offer Deferral	-	-	5,778	2,323	1,530	2,604	3,099	3,257	1,505	2,043	2,121	3,557	27,817
74	Interest	-	-	14	35	45	55	70	86	98	107	118	133	761
75	YTD Standard Offer Deferral	-	-	5,792	8,150	9,725	12,384	15,553	18,896	20,499	22,649	24,888	28,578	28,578
76	December 31, 1998 Standard Offer Balance per Filing (4 mill Differential)													11,320
77	December 31, 1998 Standard Offer Balance Adjustment													17,258
78														
79	Default Service Deferral													
80	Cost of Power	-	-	19	51	96	192	352	403	415	458	536	724	3,246
81	Sales for Resale	-	-	(4)	(9)	(18)	(38)	(51)	(42)	(64)	(90)	(113)	(137)	(566)
82	Default Service Revenues	-	-	(8)	(36)	(74)	(130)	(254)	(304)	(344)	(332)	(377)	(464)	(2,323)
83	Default Service Deferral	-	-	7	6	4	24	47	57	7	36	46	123	357
84	Interest	-	-	-	-	-	-	-	1	1	1	1	1	5
85	YTD Default Service Deferral	-	-	7	13	17	41	88	146	154	191	238	362	362
86	December 31, 1998 Default Service Balance per Filing													-
87	December 31, 1998 Default Service Balance Adjustment													362

Information Request DTE-SIS-8

Please refer to Exhs. CAM-RAP-1 (Settlement) at 4, ln. 7. Please provide the source for the estimate of line losses of 1.99 percent.

Response

Please see Attachment DTE-SIS-8 for the derivation of the estimate of line losses.

INTEROFFICE CORRESPONDENCE
RATE DEPARTMENT

TO: *H. C. LAMONTAGNE*
R. H. MARTIN
B. J. BANNON

FROM: *P. J. FOLTA*

DATE: *APRIL 2,1997*

SUBJECT: *1995 ANALYSIS OF CAMBRIDGE ELECTRIC'S SYSTEM LOSSES*

Initial Note: The 1995 loss analysis study as presented below provides the most current energy and demand loss factors to date. A 1996 loss analysis study would not be available until the end of May 1997.

The purpose of this analysis is to determine cumulative demand and energy loss factors at various voltage levels within Cambridge's power system. Power losses occur throughout the system resulting in higher actual demand at the generator level as compared to metered consumption at the customer utilization levels. System line and transformer data are used to determine power losses for each hour of the year for four voltage levels at which Cambridge provides service to customers. The voltage levels are designated as 13.8 KV, primary (4.160 KV), large secondary (service taken at secondary transformer terminals) and small secondary.

The methodology used to determine losses involves four major steps. First, losses for Cambridge's system peak hour are estimated; second, losses for all other hours are calculated by adjusting the peak hour losses downward using the relationship that load losses vary proportionally with the square of the load; third, the resulting hourly losses are totaled for the year and compared to actual unaccounted Mwhs; and fourth, peak hour losses are adjusted and hourly losses are recalculated in order to eliminate any difference found in step three.

Power losses throughout the system are associated with load losses and no-load losses. Cambridge system load flow analysis at the time of the Cambridge Electric's system peak provided information on the load losses incurred from the generator down to the 13.8 KV level. Load losses for the distribution voltage levels below 13.8 KV were determined from an empirical analysis[1] based on the electrical characteristics of Cambridge's transformers, line conductors and cables during peak load conditions for the year 1979 with adjustments made to line load losses to reflect changes in line conductor mileage from 1979 to 1995. The line load losses for each voltage level below the 13.8 KV level were adjusted by the ratio of the voltage level's wire miles recorded in 1995 to the voltage level wire miles recorded in 1979. The no-load losses were obtained from the manufacturer's transformer nameplates and test reports at the voltage levels where information existed. For the voltage levels, where information was not available the no-load losses were determined from the 1979 empirical analysis of electrical characteristics of Cambridge's transformers, and then adjusted on the basis of the ratio of MVA carrying capacity of

transformers within Cambridge's territorial system in the year 1995 to the amount of its' transformer MVA carrying capacity in the year 1979.

(1) 1979 CELCO Loss Study, Gilbert Associates, Inc.
In order to obtain cumulative loss factors, further analysis is required. Loss multipliers (1 + loss factor) are developed for each voltage level by dividing the amount of power flowing in by the amount of power flowing out including any customer sales at that voltage level. The cumulative loss multiplier for a particular voltage level is the product of the current level's multiplier and all multipliers for higher voltage levels. The cumulative loss factor is then defined as the cumulative loss multiplier minus one.

When calculating loss multipliers by voltage level, customer sales by voltage levels must be known in order to correctly determine the flow of power from one level to another. Since losses are calculated hourly, customer sales by voltage level must be estimated hourly. This was accomplished by applying the overall system load factor and number of annual hours to annual sales by voltage level resulting in peak hour sales by voltage level. The peak hour sales are then converted to percentages and used in the calculation for all other hours. Schedule 1 shows the development of peak hour sales by voltage level. Schedule 2 shows the development of peak demand loss factors by voltage level.

Next, losses are calculated for each voltage level for each hour of the year by factoring down the peak losses by the square of the ratio of the actual hourly load to the peak load. Since no-load losses do not vary as a result of load level, they are held constant for each hour. The process for calculating hourly losses by voltage level is illustrated in Schedule 3. The resulting hourly losses by voltage level are aggregated over all hours and compared to actual system losses. As a result of this comparison, small secondary load losses are adjusted in order to eliminate any difference from actual system losses. Annual cumulative energy loss factors are then calculated in a similar manner to that of demand loss factors. The development of annual cumulative energy loss factors are shown in Schedule 4.

Cumulative energy loss factors by time period are calculated by following a similar process to that for the annual loss factors except that losses are aggregated over appropriate hours of the year as defined by the time periods. The cumulative loss factors by time period are also listed on Schedule 4.

If you have any questions regarding any of the above information, please call me at extention 4377.

CAMBRIDGE ELECTRIC LIGHT COMPANY

SCHEDULE 1

CUSTOMER SALES DATA

Annual Energy	=	1,478,609	MWH
Peak Load	=	290.9	MW
Load Factor	=	.5802	

VOLTAGE LEVEL	CUSTOMER SALES IN MWH	TRANS. WHEELING IN MW	CUSTOMER SALES (INC. WHEELING) IN MW
13.8 KV	652,101.9 (1)	2.10 (2)	130.40
PRIMARY	4,704.1		.93
LARGE SECONDARY	373,854.6		73.56
SMALL SECONDARY	417,203.9		82.09

Where: CUSTOMER SALES MW = $\frac{MWH}{.5802 \times 8760}$

NOTES: (1) INCLUDES PASNY MWH'S

(2) AMOUNT REFLECTS MBTA's WHEELED MW's AT TIME OF CELCO'S PEAK

CAMBRIDGE ELECTRIC LIGHT COMPANY
Schedule 2

Development of Demand Loss Factor

N	Voltage Level	Losses Load	Losses No-Load	Total	MW (IN)	MW (OUT)	Sales Amount	Sales %	LSMULT	CUM LSMULT	Loss Factor	CUM Loss Factor
1	13.8 KV	2.31	0.11	2.42	290.90	288.48	130.40	.4520	1.00839	1.00839	0.00839	0.00839
2	Primary	1.55	0.56	2.11	158.08	155.97	0.93	.0060	1.01353	1.02203	0.01353	0.02203
3	Lg. Sec.	0.47	0.61	1.08	155.04	153.96	73.56	.4778	1.00701	1.02920	0.00701	0.02920
4	Sm. Sec.	1.44	0.000	1.44	80.40	78.96	82.09	-	1.01824	1.04797	0.01824	0.04797

Where:

$MW\ (IN)_1$ = Peak Load

$MW\ (IN)_N = MW\ (OUT)_{N-1} - Sales_{N-1}$

$MN\ (OUT)_N = MW\ (IN)_N - Loss_N$

$LSMULT_N = MW\ (IN)_N / MW\ (OUT)_N$

$CUM\ LSMULT_N = LSMULT_N \times CUM\ LSMULT_{N-1}$

$LOSS\ FACTOR_N = LSMULT_N - 1$

$CUM\ LOSS\ FACTOR_N = CUM\ LSMULT_N - 1$

CAMBRIDGE ELECTRIC LIGHT COMPANY

Schedule 3

Development of Hourly Energy Losses

General Equation

$$Loss_N = \left(\frac{MW\ (IN)_N}{PK\ HOUR\ MW\ (IN)_N} \right)^2 \times PLL_N + PNLL_N$$

Where: PLL_N = Peak hour load loss @ Level N

$PNLL_N$ = Peak hour no load loss @ Level N

Voltage Level Equation

1	13.8 KV	$Loss_1$	$= \left(\frac{Load}{290.90} \right)^2$	$\times 2.31 + 0.11$
2	PRIMARY	Loss2	$= \left(\frac{MW\ (OUT)1 \times .5480}{158.08} \right)^2$	$\times 1.55 + 0.56$
3	LG Secondary	Loss3	$= \left(\frac{MW\ (OUT)2 \times .9940}{155.04} \right)^2$	$\times 0.47 + 0.61$
4	SM Secondary	Loss4	$= \left(\frac{MW\ (OUT)3 \times .5222}{80.40} \right)^2$	$\times 1.44 + 0.000$

Where: $MW\ (IN)_N = MW\ (OUT)_{N-1} \times (1 - \%\ SALES_{N-1})$

$MW\ (OUT)_N = MW\ (IN)_N - LOSS_N$

CAMBRIDGE ELECTRIC LIGHT COMPANY

SCHEDULE 4

DEVELOPMENT OF ENERGY LOSS FACTORS

	VOLTAGE LEVEL	KWH LOSSES	KWH (IN)	KWH (OUT)	TOTAL SALES	LOSS MULT	LOSS FACT	CUM LOSS MULT	CUM LOSS FACTOR
13.8KV	1	8,245,330	1,478,609,185	1,470,363,855	652,101,871	1.00561	0.00561	1.00561	0.00561
primary	2	9,818,090	818,261,984	808,443,894	4,704,101	1.01214	0.01214	1.01782	0.01782
LG SEC	3	6,837,050	803,739,793	796,902,743	373,854,577	1.00858	0.00858	1.02655	0.02655
SM. SEC	4	4,562,810	423,048,166	418,485,356	417,203,932	1.01090	~~0.01090~~	1.03775	0.03775
	AVG. 29,463,280 / 1,478,609,185					1.01993	0.01993		

CUM Loss Factor by Period

VOLTAGE LEVEL	PEAK PERIOD	LOW LOAD PERIOD A	LOW LOAD PERIOD B
1	0.00638	0.00589	0.00488
2	0.01870	0.01802	0.01715
3	0.02657	0.02621	0.02671
4	0.04024	0.03862	0.03634