Commission Data Request 3-1

Request:

Does Narragansett have a long term capital improvement budget? If so, please provide a summary by year through 2009. If not, why not?

Response:

Each year Narragansett develops a capital improvement plan based on its fiscal calendar, April 1 – March 31. Projects requiring funding in the next fiscal year are scheduled and a capital budget for the coming year is set. In addition to the more detailed capital budget for the upcoming year, the Company also forecasts capital spending over a five-year horizon. Future year budgets and forecasts are subject to change based on a needs assessment performed each year as part of the planning process.

The current forecast of capital spending for Narragansett's distribution business segment is (in millions):

FYE-2005	FYE-2006	FYE-2007	FYE-2008	FYE-2009
$40.0	$35.0	$37.0	$37.0	TBD

Notes:
1. FYE = Fiscal Year Ending (i.e.: FYE-2005 represents the period ending March 31, 2005)
2. FYE-2006 and beyond are initial capital planning forecasts. The budget for FYE-2006 will be set in January, 2005.
3. Forecasts for FYE-2009 and FYE-2010 are currently under review.

Prepared by or under the supervision of: Robert D. Sheridan

Commission Data Request 3-2

Request:

Please provide projected earnings reports and earning sharing calculations for the years 2005 through 2009. Be sure to identify expected ROE as well as both ratepayer **and** company share of earnings sharing.

Response:

Due to the market sensitive nature of earnings projections, the Company does not publish long-term earnings projections. However, attached please find schedules that provide estimates of the requested information for the period 2005 through 2009 based on a range of key assumptions. The analysis is based on the preliminary estimated 2005 Company cost of service provided with the response to Commission Data Request 1-91 incorporating a merger savings allowance of $4.645 million proposed in the rate settlement, and three assumed cost escalation scenarios: (1) 2005 cost of service escalated at the rate of projected inflation, 2) cost of service held level for the balance of the period assuming the Company can produce efficiencies to offset inflation, and 3) a one-percent (1%) decrease per year in the 2005 cost of service commencing in 2005 assuming the Company can produce efficiencies that offset inflation plus an additional 1%. Each of these scenarios is presented with and without load growth projections.

Prepared by or under the supervision of: Michael D. Laflamme

Narragansett Electric Company
Projected Return on Equity and Shared Earnings
2005 - 2009
($000)

Summary

Scenario 1 = Projected 2005 Cost of Service escalated at the rate of inflation.
Scenario 2 = Projected 2005 Cost of Service with Company producing efficiencies to offset inflation.
Scenario 3 = Projected 2005 Cost of Service with Company producing efficiencies to offset inflation plus 1% decrease.

		With Projected Load Growth					Without Projected Load Growth				
		2005	2006	2007	2008	2009	2005	2006	2007	2008	2009
Scenario 1	Cumulative ROE for Sharing Purposes	9.59%	9.51%	9.41%	9.30%	9.20%	9.59%	9.17%	8.72%	8.27%	7.81%
	Cumulative Customer Shared Earnings	-	-	-	-	-	-	-	-	-	-
	Cumulative Company Shared Earnings	-	-	-	-	-	-	-	-	-	-
	Cumulative ROE After Cust Shared Earnings	9.59%	9.51%	9.41%	9.30%	9.20%	9.59%	9.17%	8.72%	8.27%	7.81%
Scenario 2	Cumulative ROE for Sharing Purposes	9.59%	9.86%	10.13%	10.40%	10.69%	9.59%	9.52%	9.45%	9.37%	9.30%
	Cumulative Customer Shared Earnings	-	-	-	-	$ 1,953	-	-	-	-	-
	Cumulative Company Shared Earnings	-	-	-	-	$ 1,953	-	-	-	-	-
	Cumulative ROE After Cust Shared Earnings	9.59%	9.86%	10.13%	10.40%	10.59%	9.59%	9.52%	9.45%	9.37%	9.30%
Scenario 3	Cumulative ROE for Sharing Purposes	10.02%	10.49%	10.96%	11.44%	11.91%	10.02%	10.15%	10.28%	10.40%	10.52%
	Cumulative Customer Shared Earnings	-	-	$ 2,896	$ 7,851	$17,053	-	-	-	-	$ 243
	Cumulative Company Shared Earnings	-	-	$ 2,896	$ 7,851	$12,720	-	-	-	-	$ 243
	Cumulative ROE After Cust Shared Earnings	10.02%	10.49%	10.73%	10.97%	11.10%	10.02%	10.15%	10.28%	10.40%	10.51%

Narragansett Electric Company
Projected Return on Equity and Shared Earnings
2005 - 2009

SCENARIO 1

		With Projected Load Growth					Without Projected Load Growth				
Line		**2005**	**2006**	**2007**	**2008**	**2009**	**2005**	**2006**	**2007**	**2008**	**2009**
1	Projected Load Growth (a)		1.30%	1.34%	1.38%	1.42%		0.00%	0.00%	0.00%	0.00%
2	Proposed Distribution Rate Revenue	215,604	218,407	221,334	224,388	227,574	215,604	215,604	215,604	215,604	215,604
3	Miscellaneous Operating Revenues	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
4		220,604	223,407	226,334	229,388	232,574	220,604	220,604	220,604	220,604	220,604
5											
6	Projected Total Cost of Service	220,403 (b)					220,403				
7	Less: Income Taxes	(16,451) (b)					(16,451)				
8	Preferred Equity Return	(1,225) (b)					(1,225)				
9	Common Equity Return	(27,962) (b)					(27,962)				
10	Inflation Projections (c)		1.64%	1.86%	1.82%	1.85%		1.64%	1.86%	1.82%	1.85%
11	Pre-tax Cost of Service	174,766	177,632	180,936	184,229	187,637	174,766	177,632	180,936	184,229	187,637
12	Company Shared Savings Allowance	4,645	4,645	4,645	4,645	4,645	4,645	4,645	4,645	4,645	4,645
13											
14	Projected COS Inluding Shared Savings	179,411	182,277	185,581	188,874	192,282	179,411	182,277	185,581	188,874	192,282
15											
16	Taxable Income	41,193	41,130	40,753	40,514	40,292	41,193	38,327	35,023	31,730	28,322
17	Income taxes @ 35%	(14,418)	(14,396)	(14,264)	(14,180)	(14,102)	(14,418)	(13,415)	(12,258)	(11,106)	(9,913)
18		26,776	26,735	26,489	26,334	26,190	26,776	24,913	22,765	20,625	18,409
19	Projected Preferred Equity Dividend	(1,225)	(1,243)	(1,262)	(1,281)	(1,300)	(1,225)	(1,243)	(1,262)	(1,281)	(1,300)
20											
21	Projected Income Available for Common Equity	25,551	25,491	25,227	25,053	24,890	25,551	23,669	21,503	19,344	17,109
22											
23	Projected Imputed Common Equity	266,300 (b)	270,295	274,349	278,464	282,641	266,300	270,295	274,349	278,464	282,641
24											
25	**Annual Return on Equity**	**9.59%**	**9.43%**	**9.20%**	**9.00%**	**8.81%**	**9.59%**	**8.76%**	**7.84%**	**6.95%**	**6.05%**
26											
27	**Cumulative Average Return on Equity**	**9.59%**	**9.51%**	**9.41%**	**9.30%**	**9.20%**	**9.59%**	**9.17%**	**8.72%**	**8.27%**	**7.81%**
28											
29	Cumulative Shared Earnings										
30	Cust Shared Earnings - 50/50 bandwidth	-	-	-	-	-	-	-	-	-	-
31	Cust Shared Earnings - 75/25 bandwidth	-	-	-	-	-	-	-	-	-	-
32	**Cumulative Customer Shared Earnings**	-	-	-	-	-	-	-	-	-	-
33											
34	Co. Shared Earnings - 50/50 bandwidth	-	-	-	-	-	-	-	-	-	-
35	Co. Shared Earnings - 75/25 bandwidth	-	-	-	-	-	-	-	-	-	-
36	**Cumulative Company Shared Earnings**	-	-	-	-	-	-	-	-	-	-
37											
38	**Cumulative ROE after Cust. Shared Earnings**	**9.59%**	**9.51%**	**9.41%**	**9.30%**	**9.20%**	**9.59%**	**9.17%**	**8.72%**	**8.27%**	**7.81%**

(a) Per Docket 3617 Distribution Rate Plan Stipulation and Settlement, Exhibit 7 Page 2, kWh Growth Assumptions.
(b) From Response to Commission Data Request 1-91. Equity growth based on average 2001 through 2003 actual rate base growth rate of 1.5%.
(c) Per Docket 3617 Distribution Rate Plan Stipulation and Settlement, Exhibit 7 Page 2.

Narragansett Electric Company
Projected Return on Equity and Shared Earnings
2005 - 2009

SCENARIO 2

		With Projected Load Growth					Without Projected Load Growth				
Line		2005	2006	2007	2008	2009	2005	2006	2007	2008	2009
1	Projected Load Growth (a)		1.30%	1.34%	1.38%	1.42%		0.00%	0.00%	0.00%	0.00%
2	Proposed Distribution Rate Revenue	215,604	218,407	221,334	224,388	227,574	215,604	215,604	215,604	215,604	215,604
3	Miscellaneous Operating Revenues	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
4		220,604	223,407	226,334	229,388	232,574	220,604	220,604	220,604	220,604	220,604
5											
6	Projected Total Cost of Service	220,403 (b)					220,403				
7	Less: Income Taxes	(16,451) (b)					(16,451)				
8	Preferred Equity Return	(1,225) (b)					(1,225)				
9	Common Equity Return	(27,962) (b)					(27,962)				
10	Inflation Projections (c)		0.00%	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%
11	Pre-tax Cost of Service	174,766	174,766	174,766	174,766	174,766	174,766	174,766	174,766	174,766	174,766
12	Company Shared Savings Allowance	4,645	4,645	4,645	4,645	4,645	4,645	4,645	4,645	4,645	4,645
13											
14	Projected COS Inluding Shared Savings	179,411	179,411	179,411	179,411	179,411	179,411	179,411	179,411	179,411	179,411
15											
16	Taxable Income	41,193	43,996	46,923	49,977	53,164	41,193	41,193	41,193	41,193	41,193
17	Income taxes @ 35%	(14,418)	(15,399)	(16,423)	(17,492)	(18,607)	(14,418)	(14,418)	(14,418)	(14,418)	(14,418)
18		26,776	28,598	30,500	32,485	34,556	26,776	26,776	26,776	26,776	26,776
19	Projected Preferred Equity Dividend	(1,225)	(1,243)	(1,262)	(1,281)	(1,300)	(1,225)	(1,243)	(1,262)	(1,281)	(1,300)
20											
21	Projected Income Available for Common Equity	25,551	27,354	29,238	31,204	33,256	25,551	25,532	25,514	25,495	25,476
22											
23	Projected Imputed Common Equity	266,300 (b)	270,295	274,349	278,464	282,641	266,300	270,295	274,349	278,464	282,641
24											
25	**Annual Return on Equity**	**9.59%**	**10.12%**	**10.66%**	**11.21%**	**11.77%**	**9.59%**	**9.45%**	**9.30%**	**9.16%**	**9.01%**
26											
27	**Cumulative Average Return on Equity**	**9.59%**	**9.86%**	**10.13%**	**10.40%**	**10.69%**	**9.59%**	**9.52%**	**9.45%**	**9.37%**	**9.30%**
28											
29	Cumulative Shared Earnings										
30	Cust Shared Earnings - 50/50 bandwidth	-	-	-	-	1,953	-	-	-	-	-
31	Cust Shared Earnings - 75/25 bandwidth	-	-	-	-	-	-	-	-	-	-
32	**Cumulative Customer Shared Earnings**	-	-	-	-	**1,953**	-	-	-	-	-
33											
34	Co. Shared Earnings - 50/50 bandwidth	-	-	-	-	1,953	-	-	-	-	-
35	Co. Shared Earnings - 75/25 bandwidth	-	-	-	-	-	-	-	-	-	-
36	**Cumulative Company Shared Earnings**	-	-	-	-	**1,953**	-	-	-	-	-
37											
38	**Cumulative ROE after Cust. Shared Earnings**	**9.59%**	**9.86%**	**10.13%**	**10.40%**	**10.59%**	**9.59%**	**9.52%**	**9.45%**	**9.37%**	**9.30%**

(a) Per Docket 3617 Distribution Rate Plan Stipulation and Settlement, Exhibit 7 Page 2, kWh Growth Assumptions.
(b) From Response to Commission Data Request 1-91. Equity growth based on average 2001 through 2003 actual rate base growth rate of 1.5%.
(c) Assumes Company can generate efficiencies to offset inflation.

Narragansett Electric Company
Projected Return on Equity and Shared Earnings
2005 - 2009

SCENARIO 3

		With Projected Load Growth					Without Projected Load Growth				
Line		**2005**	**2006**	**2007**	**2008**	**2009**	**2005**	**2006**	**2007**	**2008**	**2009**
1	Projected Load Growth (a)		1.30%	1.34%	1.38%	1.42%		0.00%	0.00%	0.00%	0.00%
2	Proposed Distribution Rate Revenue	215,604	218,407	221,334	224,388	227,574	215,604	215,604	215,604	215,604	215,604
3	Miscellaneous Operating Revenues	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
4		220,604	223,407	226,334	229,388	232,574	220,604	220,604	220,604	220,604	220,604
5											
6	Projected Total Cost of Service	220,403 (b)					220,403				
7	Less: Income Taxes	(16,451) (b)					(16,451)				
8	Preferred Equity Return	(1,225) (b)					(1,225)				
9	Common Equity Return	(27,962) (b)					(27,962)				
10	Inflation Projections (c)	(1,748) (c)	-1.00%	-1.00%	-1.00%	-1.00%	(1,748)	-1.00%	-1.00%	-1.00%	-1.00%
11	Pre-tax Cost of Service	173,018	171,288	169,575	167,879	166,200	173,018	171,288	169,575	167,879	166,200
12	Company Shared Savings Allowance	4,645	4,645	4,645	4,645	4,645	4,645	4,645	4,645	4,645	4,645
13											
14	Projected COS Inluding Shared Savings	177,663	175,933	174,220	172,524	170,845	177,663	175,933	174,220	172,524	170,845
15											
16	Taxable Income	42,941	47,474	52,114	56,864	61,729	42,941	44,671	46,384	48,080	49,759
17	Income taxes @ 35%	(15,029)	(16,616)	(18,240)	(19,902)	(21,605)	(15,029)	(15,635)	(16,234)	(16,828)	(17,416)
18		27,912	30,858	33,874	36,961	40,124	27,912	29,036	30,150	31,252	32,343
19	Projected Preferred Equity Dividend	(1,225)	(1,243)	(1,262)	(1,281)	(1,300)	(1,225)	(1,243)	(1,262)	(1,281)	(1,300)
20											
21	Projected Income Available for Common Equity	26,687	29,615	32,612	35,681	38,824	26,687	27,793	28,888	29,971	31,043
22											
23	Projected Imputed Common Equity	266,300 (b)	270,295	274,349	278,464	282,641	266,300	270,295	274,349	278,464	282,641
24											
25	**Annual Return on Equity**	**10.02%**	**10.96%**	**11.89%**	**12.81%**	**13.74%**	**10.02%**	**10.28%**	**10.53%**	**10.76%**	**10.98%**
26											
27	**Cumulative Average Return on Equity**	**10.02%**	**10.49%**	**10.96%**	**11.44%**	**11.91%**	**10.02%**	**10.15%**	**10.28%**	**10.40%**	**10.52%**
28											
29	Cumulative Shared Earnings										
30	Cust Shared Earnings - 50/50 bandwidth	-	-	2,896	7,851	10,554	-	-	-	-	243
31	Cust Shared Earnings - 75/25 bandwidth	-	-	-	-	6,499	-	-	-	-	-
32	**Cumulative Customer Shared Earnings**	**-**	**-**	**2,896**	**7,851**	**17,053**	**-**	**-**	**-**	**-**	**243**
33											
34	Co. Shared Earnings - 50/50 bandwidth	-	-	2,896	7,851	10,554	-	-	-	-	243
35	Co. Shared Earnings - 75/25 bandwidth	-	-	-	-	2,166	-	-	-	-	-
36	**Cumulative Company Shared Earnings**	**-**	**-**	**2,896**	**7,851**	**12,720**	**-**	**-**	**-**	**-**	**243**
37											
38	**Cumulative ROE after Cust. Shared Earnings**	**10.02%**	**10.49%**	**10.73%**	**10.97%**	**11.10%**	**10.02%**	**10.15%**	**10.28%**	**10.40%**	**10.51%**

(a) Per Docket 3617 Distribution Rate Plan Stipulation and Settlement, Exhibit 7 Page 2, kWh Growth Assumptions.
(b) From Response to Commission Data Request 1-91. Equity growth based on average 2001 through 2003 actual rate base growth rate of 1.5%.
(c) Assumes Company can generate efficiencies to offset inflation plus 1% commencing in 2005.

Commission Data Request 3-3

Request:

Please set forth the actual kWh sales for the years 2002, 2003 and estimated for 2004. Also please provide the weather normalized kWh sales for the same time periods.

Response:

The data requested is shown in the table below:

Year	Actual kWh Deliveries	Weather-Normalized kWh Deliveries
2002	7,515,614,036	7,393,425,018
2003	7,694,091,639	7,567,536,732
2004*	7,752,018,112	7,767,132,409

* 2004 data is comprised of 8 months of actual data and 4 months of estimated data.

Prepared by or under the supervision of: Alfred P. Morrissey, Jr.

Commission Data Request 3-4

Request:

The response to Commission data request 1-37 seems to indicate that the savings resulting from the 2003 VERO are expected to last approximately 5 years (2004-2008). If this is the case, why is it appropriate to amortize the VERO costs over 10 years as opposed to making the amortization period match the benefit period?

Response:

The VERO amortization period ultimately impacts the Company's cost of service going forward. A shorter amortization period would have the impact of increasing the Company's cost of service in the near term and reducing earnings over the period. The amortization period was a negotiated issue among the settling parties and a ten-year amortization period was agreed to in the comprehensive resolution of the underlying cost of service included in the proposed settlement. However, as indicated in the response to Commission Data Request 1-37, the VERO was conducted in concert with the renegotiation of the Company's field force union contracts. The renegotiated contracts facilitate the Company's decision not to replace a certain number of workers who accepted the VERO. In addition, these renegotiated contracts provide for increased flexibility to employ contractor services and greater work force flexibility than under prior contracts, the benefits of which the Company cannot quantify at this time. The analysis provided with the response to Commission Data Request 1-37 measured only the net labor and benefits savings of the VERO based on an expected remaining service life of the workers who accepted the VERO.

Prepared by or under the supervision of: Michael D. Laflamme

Commission Data Request 3-5

Request:

The settlement uses GDPIPD as a factor in various calculations.

a. What are the factors that determine GDPIPD?
b. What other economic indicators are available that could have been used instead of GDPIPD?
c. Instead of GDPIPD, could the typical cost increases of other similar electric distribution companies be used as a benchmark that Narragansett's performance could be compared to?

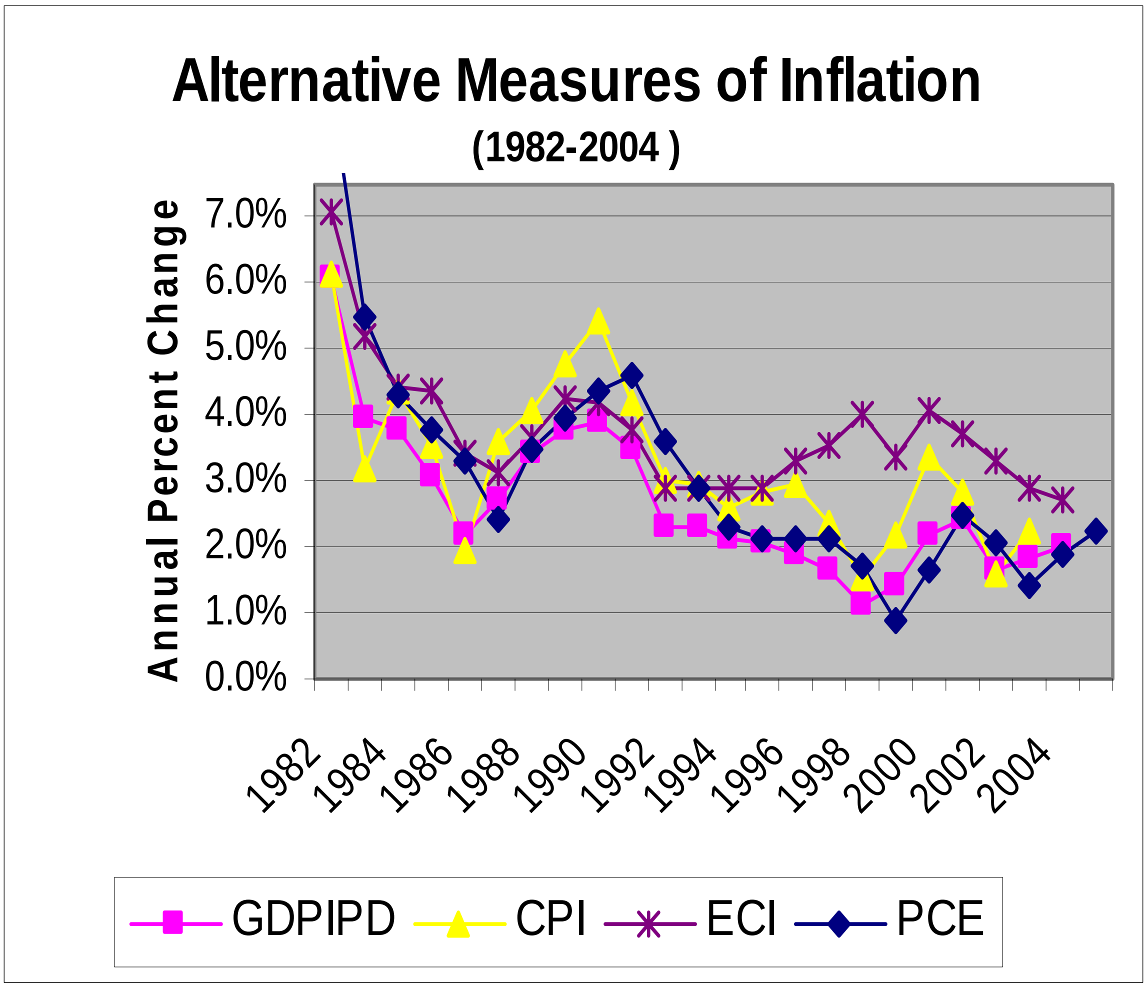
Response:

a. The Gross Domestic Product Implicit Price Deflator (GDPIPD) is used in the Settlement to define the potential excessive inflation exogenous event (Section 2(B)(4)), as well as in determining the reopener indices and thresholds (Section 4(B); Exhibit 7). GDPIPD is a measure of inflation from year to year using the country's Gross Domestic Product (GDP) as the basis. That is, the GDPIPD measures inflation in the prices of all goods and services produced by the U.S. economy. Factors that go into determining the GDPIPD include the prices of personal consumption expenditures, gross private domestic investment, net exports of goods and services, and government consumption expenditures and gross investment. The GDPIPD is produced by the U.S. Department of Commerce, Bureau of Economic Analysis (BEA). Detailed information about the GDPIPD and its uses can be found on the BEA's website, www.bea.doc.gov.

b. Use of the GDPIPD to define the excessive inflation exogenous event, and in determining the reopener indices and thresholds, is a continuation of what was agreed with respect to these matters in the Third Amended Stipulation and Settlement in Docket No. 2930 ("Current Settlement"). The parties did not propose in the Settlement to change the measure of inflation that was adopted in the Current Settlement. However, other common inflation measures include the Consumer Price Index (CPI), the Personal Consumption Expenditures Price Index (PCE), the Employment Cost Index (ECI), and the Producer Price Index (PPI). The CPI, the most widely used inflation measure, reflects changes in the prices a fixed basket of consumer goods and services purchased by a typical urban wage earner. The PCE measures changes in the prices of goods and services purchased by individuals, nonprofit institutions that primarily serve individuals, private noninsured welfare funds, and private trust funds. The ECI measures changes in compensation costs, including wages, salaries and employer costs for employee benefits. The PPI measures changes in the price of raw materials and unfinished goods used by manufacturers. This includes the cost of raw materials such as food, metals, ore, lumber, oil, gas and many other commodities, but it does not include the price of services.

Commission Data Request 3-5 (continued)

All of these measures of inflation are closely correlated with each other and, other than the PPI, are all reflective of the cost increases faced by Narragansett. When there is inflation in the economy, Narragansett's compensation, outsourcing, rental, plant and materials costs all increase along with the GDPIPD, CPI, PCE and ECI. The CPI and the ECI are correlated both because firms adjust prices to keep up with compensation growth and because firms adjust wages to keep pace with inflation. The PCE is closely related to the CPI for obvious reasons. However, Narragansett's costs are most closely related to the GDPIPD because this index includes not only employment and consumer costs but also the prices of other goods and services purchased by the Company. Moreover, the GDPIPD generally shows the least amount of inflation compared to these other indexes. This is shown in the chart below, which also illustrates the correlation between all of the price indexes considered:



Commission Data Request 3-5 (continued)

c. As discussed above, use of the GDPIPD is a continuation of the inflation measure that was agreed in the Current Settlement. The parties did not propose to change this measure in this Settlement. Nevertheless, using a regional index of distribution rates as a benchmark has been used in rate plans in other states. For example, Narragansett's affiliate, Massachusetts Electric Company (Mass. Electric), is operating under a rate plan which includes a distribution rate freeze through February 2005, followed by a "rate index period" from March 1, 2005 through December 31, 2009. *See* Rate Plan Settlement, New England Electric System and Eastern Utilities Associates, M.D.T.E. Docket No. 99-47 (2000). Each year during the rate index period, Mass. Electric's average distribution rate is compared to an average distribution rate of a regional index comprised of similarly unbundled investor-owned electric utilities in the Northeast (New England, New York, New Jersey and Pennsylvania). As the regional distribution rate index changes annually (up or down), Mass. Electric's distribution rates are correspondingly adjusted automatically. It should be noted that unlike general inflation measures such as those listed in response 3-5(b), above, changes in the regional index may reflect the impact of several other factors aside from general inflation (e.g., varying capital investment programs, costs of commission-mandated programs, tax changes, extraordinary storm cost recoveries, etc.).

Prepared by or under the supervision of: Alfred P. Morrissey, Jr. and Carlos A. Gavilondo

Commission Data Request 3-6

Request:

With regard to the storm fund, if the Commission were to determine that a funding cap is appropriate, would the company have any objection to an annual review of the funding level? Would the answer be different if no cap was put in place?

Response:

Neither the Current Settlement nor the Settlement in this case contains any provision regarding a cap on the storm fund. Thus, a determination by the Commission to establish a cap on the storm fund would, in and of itself, not implicate any provision in the Settlement. As indicated in the Company's response to Commission Data Request 1-42, any storm fund cap that may be determined should be consistent with the objectives of the storm fund; i.e., to enable the Company to pay the incremental non-capital cost of an extraordinary storm event without incurring a significant deficit balance and without having to implement periodic customer surcharges.

If the Commission were to establish a storm fund cap, such a cap could be achieved without need to modify the Settlement by implementing a refund or transfer mechanism such as described in the response by the Division of Public Utilities and Carriers to Commission Data Request 1-30(b). Alternatively, if the settling parties concurred, the Company would not object to an annual review of the level of funding of the storm fund; provided that the main objectives of the storm fund are still served. The Company does not believe it is necessary for the Commission to establish a specific storm fund cap in order for it to examine the annual funding level of the storm fund.

Prepared by or under the supervision of: Carlos A. Gavilondo

Commission Data Request 3-7

Request:

Referring to the response to Commission data request 1-56, please identify the evidence and/or data upon which the final sentence is based.

Response:

The last sentence in the response to Commission Data Request 1-56 referred to the preceding sentence of that response. That is, the availability of a low income rate makes electric service more affordable, which provides a "*greater opportunity* for these customers *to remain current on their payments* for the service." (Emphasis added). If the number of customers remaining current on their payments increased as a result of there being a low income rate, it would reduce the cost of collection activities and bad debt expense for all customers. The Company does not have any specific data or evidence upon which this sentence is based.

Prepared by or under the supervision of: Carlos A. Gavilondo

Commission Data Request 3-8

Request:

With regard to the response to Commission data request 1-61, what is the rationale for "assuming no growth in the number of customers taking service on Rate A-60 or their aggregate load…"?

Response:

Commission data request 1-61 requested a calculation of the low income subsidy based on the rates proposed in the Settlement for the period 2005 through 2009. The calculation provided in response to that data request was intended to show the change in the annual subsidy that would occur as a result of the "phase-in" of the Rate A-60 distribution kWh tail block charges and did not account for any change in number of customers or kWh deliveries over the five-year period.

The Company does not have a rate class kWh forecast available for the entire five-year period. However, the attached workpaper shows the estimated incremental annual subsidy that would result from the estimated increase in the number of customers and annual kWh deliveries to Rate A-60 customers based on the most recent forecast for the calendar years 2004 through 2007. The billing determinants for calendar years 2008 and 2009 were estimated by increasing the number of annual bills by 0.5% each year and the annual kWh deliveries by 1.5% each year.

Prepared by or under the supervision of: Jeanne A. Lloyd

The Narragansett Electric Company

Calculation of Annual Low Income Subsidy for 2005 through 2009

Rate A-60 Estimated Billing Determinants

	2005 (1)	2006 (1)	2007 (1)	2008 (2)	2009 (2)
Number of Bills	385,005	388,764	390,420	392,372	394,334
First 500 kWhs (1)	141,900,465	144,294,038	146,709,774	148,910,420	151,144,076
kWhs in excess of 500	50,179,535	51,025,962	51,880,226	52,658,430	53,448,306
Total kWhs	192,080,000	195,320,000	198,590,000	201,568,850	204,592,383

(1) From Company Rate Class Customer and GWh Forecast
(2) Estimated as annual growth in number of customers of 0.05% and annual growth in kWh deliveries of 1.5%

Estimated Annual Subsidy

Year		2005	2006	2007	2008	2009
Proposed Rate A-60 Charges	Units	Charges	Charges	Charges	Charges	Charges
Customer Charge	385,005	$0.00	$0.00	$0.00	$0.00	$0.00
Initial Block Charge	141,900,465	$0.01690	$0.01690	$0.01690	$0.01690	$0.01690
Tail Block Charge	50,179,535	$0.03384	$0.03383	$0.03382	$0.03381	$0.03380
Proposed Rate A-16 Charges	Units	Charges	Charges	Charges	Charges	Charges
Customer Charge	385,005	$2.75	$2.75	$2.75	$2.75	$2.75
A16 kWh Charge	192,080,000	$0.03384	$0.03383	$0.03382	$0.03381	$0.03380

Rate A-60 Revenues	Revenues	Revenues	Revenues	Revenues	Revenues
Customer Charge	$0	$0	$0	$0	$0
Initial Block Charge	$2,398,118	$2,438,569	$2,479,395	$2,516,586	$2,554,335
Tail Block Charge	$1,698,075	$1,726,208	$1,754,589	$1,780,382	$1,806,553
Revenue on Rate A-60	$4,096,193	$4,164,778	$4,233,984	$4,296,968	$4,360,888
Rate A-16 Revenues	Revenues	Revenues	Revenues	Revenues	Revenues
Rate A16 Customer Charge	$1,058,764	$1,069,101	$1,073,655	$1,079,023	$1,084,418
Rate A16 kWh Charge	$6,499,987	$6,607,676	$6,716,314	$6,815,043	$6,915,223
Revenue on A16	$7,558,751	$7,676,777	$7,789,969	$7,894,066	$7,999,641
Subsidy	$3,462,558	$3,511,999	$3,555,984	$3,597,098	$3,638,753
Incremental Annual Subsidy		$49,441	$43,985	$41,114	$41,655

Commission Data Request 3-9

Request:

With regard to the response to Commission data request 1-93:

a) Please provide evidence to support column (a), Rate Year Number of Bills
b) Please provide evidence to support column (i), 2005 Forecasted Rate Class kWhs

Response:

The Rate Year forecast of the number of bills and kWh levels was obtained from monthly econometric models relating the Company's monthly kWh deliveries and customer counts to economic/demographic variables, weather variables and other explanatory variables affecting the demand for electricity.

Historical kWh deliveries and customer count data were taken from Company records. Historical and forecast economic and demographic explanatory variables were obtained under subscription service from Economy.com, a leading economic consulting firm which produces national, state and local economic forecasts in line with the consensus view. Historical weather explanatory variables were collected from the National Weather Service's Providence, RI weather station. Forecasted weather variables were set equal to normal, defined as a ten-year historical average. Other explanatory variables used in the models included electricity price, number of days billed per month and monthly hours of daylight. These variables were calculated from Company records, meter reading schedules and monthly sunrise/sunset times.

Separate econometric models were developed for the Company's major classes of service: residential; commercial; industrial; street lighting; and sales for resale. The residential class accounts for approximately 39% of total kWh deliveries while the commercial and industrial classes account for approximately 44% and 16% of total kWh deliveries, respectively. Street lighting accounts for slightly less than 1% of total kWh deliveries while "sales for resale" makes up an insignificant proportion of total kWh deliveries.

The residential and commercial econometric models were specified as kWh use per customer models. That is, total monthly deliveries to these classes were divided by the number of customers in each class and regressed against the explanatory variables. Separate econometric models were then used to forecast the number of customers in these classes. Total forecasted deliveries in each class were then taken as the product of the kWh use per customer forecast and the customer forecast. For the industrial, street lighting and sales for resale classes, on the other hand, total kWh deliveries themselves were regressed against the explanatory variables.

Commission Data Request 3-9 (continued)

For the residential kWh usage per customer models, the explanatory variables were heating degree days (HDD), cooling degree days (CDD), household size, real income per capita, electricity price, number of days billed and hours of daylight. These variables were combined into residential heating, cooling and base load explanatory indexes. For the residential customer model, explanatory variables were number of households and lagged dependent variables. For the commercial use per customer models, explanatory variables included HDD, CDD, real commercial output, electricity price, number of days billed and hours of daylight. These variables were combined into commercial heating, cooling and base load explanatory indexes. For the commercial customer count model, the explanatory variables were non-manufacturing employment and a moving average term. For the industrial kWh sales model, the explanatory variables were real industrial output, electricity price, CDD and monthly indicator variables.

The resulting class of service kWh and customer forecasts were allocated to rate classes based on each rate class's share of the total class of service kWh and customer counts over the most recent twelve month historical period. The exception was closed rate classes which, by definition, should show no increase in the number of customers. These rate classes were assigned a declining share of total class kWh and customer counts, based on recent trends.

The Rate Year billing units for Streetlighting rates S-10, S-12 and S-14 were not based on the forecast methodology described above. For these classes, rate year kWh were estimated by multiplying the annual kWh per luminaire type by the number of each type of luminaire in inventory as of year end December 2003. The detail of this calculation was provided in the Company's response to Commission 1-93, pages 6 to 8.

Prepared by of under the supervision of: Alfred P. Morrissey, Jr. and Jeanne A. Lloyd

Commission Data Request 3-10

Request:

With regard to the response to Commission data request 1-80:

a) What non-utility property would the utility own?
b) Where did the money to buy the property come from?

Response:

a) As of December 31, 2003, Narragansett had $1,524,934 of non-utility property recorded on its balance sheet. These assets are recorded as Other Property and Investments and are not included in the Company's rate base for cost of service or earnings report purposes. The majority of non-utility property consists of land which was acquired for purposes other than the delivery of the Company's distribution and/or transmission services. One example is the acquisition of land surrounding substation properties the intended use of which is to provide a buffer zone around the substation property. Another example is the acquisition of property intended for potential future use.

b) The money to buy these properties came from the Company's general funds.

Prepared by or under the supervision of: Michael D. Laflamme

Commission Data Request 3-11

Request:

Please explain why it is appropriate to use $233,047,000 as the benchmark cost of service for purposes of the reopener provision.

Response:

The $233,047,000 appears in Exhibit 7 (Reopener Provision), page 2 of 3, line 23. This amount represents the 2005 rate year revenue of $230,847,000 that would be produced under the Company's current rates (see also Exhibit 1, page 1, line 1), plus the lost revenue embedded in current rates of $2,200,000 resulting from the expansion of the low income discount. Under the terms of the Current Settlement, the Company is authorized to track and recover this lost revenue from customers through a reconciling adjustment factor, or by rolling recovery into distribution rates at the Company's first rate case to establish new distribution rates. Thus, the $233,047,000 amount simply represents the Company's pro forma 2005 revenues, plus the $2,200,000 low income expansion amount. It is important to note that the distribution rates established at the outset of the Current Settlement also included an annual $2.7 million settlement credit, hold harmless credits valued at $425,000 annually and an estimated $575,000 annually of low income credit expansion.

The Reopener Provision in the Current Settlement, as well as in the proposed Settlement, provides a mechanism for comparing, on an average cents/kWh basis, any Company-proposed distribution rate change occurring after the initial rate freeze period against a baseline average distribution revenue per kWh. Under the Reopener Provision, if the Company were to request a distribution rate increase any time during the 20-year period following the 2000 merger of Narragansett, the former Blackstone Valley Electric Company, and the former Newport Electric Corporation, such proposed average distribution revenue per kWh percentage increase would be compared to the average distribution revenue per kWh percentage increase customers could have reasonably expected under two separate cost escalation scenarios. Such "expected" rates are represented by Line B (Cumulative GDPIPD Threshold) in Exhibit 7, page 1 of 3, which reflects the average of distribution rates established at the outset of the Current Settlement escalated at the rate of inflation. Line A (Cumulative Reopener Threshold) of that graph represents a suppressed rate path agreed to in the Current Settlement which reflects the average of distribution rates established at the outset of the Current Settlement held flat for the initial five year rate freeze period, escalated by a reopener index rate of 1.9% annually for the years 2005 through 2009, and 80% of inflation thereafter. This Reopener Threshold rate path (Line A) represents the average distribution rate level the Company must stay below in order to retain its share of merger savings. If any proposed distribution rate increase would result in an average distribution revenue per kWh percentage increase from then current average distribution revenue per kWh that exceeds the cumulative Reopener Threshold (Line A) percentage as shown on Line 12 of Exhibit 7, Page 2, the Company would need to prove the continued existence of its shared savings. If the proposed distribution revenue per kWh percentage increase would exceed the cumulative GDPIPD Threshold (Line B) as shown on Line 13 of Exhibit 7, Page 2, that portion

Commission Data Request 3-11 (continued)

of the shared savings in excess of Line B would be excluded from the Company's cost of service as described in the Settlement.

The parties to the Settlement have agreed that the distribution rates originally established under the Current Settlement, as adjusted to reflect the recovery of the low income expansion amount, represent the appropriate benchmark against which to compare future proposed distribution rate increases. This benchmark, if calculated in 2005, would be based on revenue of $233,047,000. This benchmark also reflects making permanent the rate reductions associated with the Settlement Credit and the Hold Harmless provision from the Current Settlement. Because the $233,047,000 is based upon the distribution rates established under the Current Settlement (adjusted for the impact of the low income expansion, but making permanent the rate reductions associated with the Settlement Credit and the Hold Harmless provision) it is appropriate to use this amount to establish the Reopener Provision baseline cents/kWh value in the proposed Settlement.

Prepared by or under the supervision of: Michael D. Laflamme