Commission Data Request 1-91

Request:

What is the expected actual cost of service for 2005? Please provide supporting schedules.

Response:

For purposes of responding to this data request, attached please find a preliminary estimated cost of service revenue requirement for 2005. This preliminary cost of service includes a merger savings allowance of $7,883,000 as is currently pending before the Commission in Docket 2930.

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Narragansett Electric
Preliminary
Intrastate Cost of Service
Rate Year 2005
Page 1

The Narragansett Electric Company

Intrastate Cost of Service
Calendar Year 2005
($000)

		Total Company Per Books 2003	Interstate Adjustments 2003 1/	Other Adjustments 2003	Intrastate 2003	Normalizing Adjustments 2005	Intrastate Cost of Service 2005	Page Ref
1	Operation & Maintenance Expense	$131,002 2/	$2,753	$0	$128,249	($29,900)	$98,349	2
2	Transmission Wheeling Costs - NEP	$42,641	$0	$42,641	$0	$0	$0	
3	Conservation and Load Management Expense	$16,848	$0	$16,848	$0	$0	$0	
4	Purchased Power Expense	$469,398	$0	$469,398	$0	$0	$0	
5	Donations	$698	$21	$0	$677	$0	$677	
6	Fuel Expense	$0	$0	$0	$0	$0	$0	
7	Depreciation Expense	$36,742	$3,741	$0	$33,001	$2,518	$35,519	10
8	Other Amortization Expense	$295	$0	$0	$295	$0	$295	
9	Gross Earnings Tax	$28,129	$0	$28,129	$0	$0	$0	
10	Municipal Taxes	$20,274	$3,141	$0	$17,133	$821	$17,954	11
11	FICA	$3,424	$104	$0	$3,320	($14)	$3,306	12
12	Federal Unemployment	$43	$1	$0	$42	$0	$42	
13	State Unemployment	$190	$6	$0	$184	$0	$184	
14	Other Misc Taxes	$260	$0	$0	$260	$0	$260	
15	Current and Deferred FIT	$17,302	-	-	-	-	$16,451	16
16	Amort. of Investment Tax Credit	($717)	$0	$0	($717)	$0	($717)	
17	Amort. of Loss on Reacquired Debt 3/	$712 3/	$103	$0	$609	$0	$609	
18	Interest on Customer Deposits	$127	$0	$0	$127	$0	$127	
19	Overall Return $532,600 * 8.89%		-	-	-	-	$47,348	13
20								
21	**Total Cost of Service**						$220,403	
22								
23	**Normalized Revenue- 2005**				**$225,847** +	**$5,000**	$230,847	
24								
25	**Excess Revenue Before Earned Savings**						($10,444)	
26								
27	**Earned Savings**						$7,883 4/	
28								
29	**Net Excess Revenue**						**($2,561)**	

1/ Interstate Allocation Study, Page 1
2/ Excludes G&T Credit of ($27,337)
3/ Intrastate Cost of Service, Page 7
4/ Per Docket 2930 First Savings Proof filing curently pending

The Narragansett Electric Company

Summary of Intrastate Operation & Maintenance Adjustments

($000)

	Amount	Reference Page
a. Bad Debt Expense Adjustment	($153)	3
b. Advertising Expense/Other Non-recoverable Expenses	($177)	3
c. Merger Integration Cost Elimination	($3,444)	3
d. Non-recurring Expense Adjustments	($1,939)	3
e. 2003 VERO Adjustments	($21,921)	3
f. Out of Period Expense Adjustment	($1,448)	3
Salary and Wage Adjustment	($552)	4
Health Care Cost Adjustment	($123)	5
Group Insurance Cost Adjustment	($14)	6
Pension Expense Adjustment	($309)	7
FAS 106 Expense Adjustment	($1,098)	8
Inflation Adjustment	$1,280	9
Total Intrastate O & M Expense Adjustments	**($29,900)**	

The Narragansett Electric Company

Operations and Maintenance Expense Normalizing adjustments
($000)

a. Adjustment to Normalize Bad Debt Expense to Actual Net Write-offs

Net Charge-offs - Average of 2002 & 2003	$4,774	
Bad Debt Expense - Average of 2002 & 2003	4,928	
Normalized Bad Debt Expense	($153)	
Customer Accounts Expense Allocation Percentage	100.00%	1/
Bad Debt Expense Adjustment	**($153)**	

b. Adjustment to Eliminate Advertising Expense (FERC Acct 930.1) and Other Non-recoverable Expenses

Advertising Expense FERC Acct 930.1 - Calendar Year 2003	($92)	
Other Non-recoverable Expenses - Calendar Year 2003	(91)	
Total	($183)	
A&G Expense Allocation Percentage	96.95%	1/
Total Adjustment	**($177)**	

c. Adjustment to Eliminate Incremental NIMO Merger Integration Costs

Total NIMO Integration Costs - Calendar Year 2003	($4,717)	
Less: Non-incremental NIMO Merger Integration Costs - Calendar Year 2003	(507)	
Incremental NIMO Merger Integration Costs	($4,210)	
10 Year amortization of '04 & '05 Incremental NIMO Merger Integration costs	$658	
	($3,553)	
A&G Expense Allocation Percentage	96.95%	1/
Incremental NIMO Merger Integration Costs Adjustment	**($3,444)**	

d. Adjustment for Non-recurring Expenses

Accrual for Insurance Liability relating to factory fire in Woonsocket, RI		
Entry recorded in August 2003	($2,000)	
A&G Expense Allocation Percentage	96.95%	1/
	($1,939)	

e. 2003 VERO Adjustment

Total VERO costs		
Entries recorded in November, December 2003	($25,122)	
Less: Amortization of costs over ten year period	2,512	
Net VERO Costs	($22,610)	
A&G Expense Allocation Percentage	96.95%	1/
Total VERO adjustment	**($21,921)**	

f. Out of Period Expense Adjustment

Prior Year Distribution Dispatch costs recorded in 2003	($1,448)
A&G Expense Allocation Percentage	100.00%
	($1,448)

1/ Interstate Allocation Study, Page 5

The Narragansett Electric Company
Test Year Ended 12/31/03 - Interstate/Intrastate Salary and Wage Analysis

				Union	Non-Union		
1	Total Nov 2003 Active Employee Base Pay			$1,792,903	$783,902		
2	Annualized			x 52/4	x 12		
3	2003 Active Employee Annual Regular Pay			$23,307,741	$9,406,824		
4	Annualized Non-Union Weekly Regular Pay				333,453		
5	Nov. 2003 Active Employee Annualized Regular Pay			$23,307,741	$9,740,277		
6	Estimated VERO Impact- reduction savings			($4,453,238)	($1,786,671)		
7	Estimated VERO Impact- add back costs			$858,048	$792,363		
8	Total Nov. 2003 Active Employee Annual Regular Pay Adjusted for VER(			$19,712,551	$8,745,969		
9	% charged to O&M			59.81%	59.81%		
10	Annualized Regular Pay Charged to O&M			$11,790,077	$5,230,964		
11	2003 Actual Active Employee Overtime Labor Charged to O&M			$3,804,375	$487,556		
12	Total 2003 Active Employee Annual Pay (Regular & O.T.) O&M Wages			$15,594,452	$5,718,520		
13	Projected 2004 Wage Increase			6.25% 1/	3.16% 2/		
14	Estimated 2004 Normalized Annual Reg and OT Wages			$16,569,105	$5,899,225		
15	Projected 2005 Wage Increase			2.03% 1/	1.58% 2/		
16	Estimated 2005 Normalized Annual Reg and OT Wages			$16,905,458	$5,992,433		
17	Estimated One-time compensation awards:	GRID Goals	3.25%	$549,427	$194,754		
18		ICP	03 Level		$169,395		
19		ARB	3.50%		$191,853		
20		Spot Bonus	1.50%		$82,223		
21		PBB	2.25%	$380,373			
22	Estimated 2005 Active Employee Total O&M Wages			$17,835,258	$6,630,658		$24,465,916
23							
24	Test Year 2003 O&M Wages (Form 1 P 355)						$24,569,043
25	O&M Wage Adjustment for Narragansett Employees						($103,127)
26	VERO savings adjustment for wages allocated from Service Company					4/	($472,875)
27	Total Wage Adjustment						($576,002)
28	Intrastate Percentage					3/	95.84%
29							
30	**Total Intrastate Wage Adjustment**						($552,011)

		2004	2005
1/	Union Wage Increase		
	Annual Percentage Increase	6.25%	3.25%
	# months of increase in period	12	7.5
	Annual % Increase	6.25%	2.03%
2/	Non-Union Wage Increase	2004	2005
	Annual Percentage Increase	3.16%	3.16%
	# months of increase in period	12	6.0
	Annual % Increase	3.16%	1.58%

3/ Interstate Allocation Study, Page 5 4.17%

4/ VERO adjustment for Service Company allocations:

	2003
Total Salaries originating from Service Co.	$127,253,507
Total Salaries allocated to Narragansett O&M	$10,883,631
Percentage of Service Co. Total Salaries to Narr. O&M	8.55%
Total VERO Salary savings from Service Co. employee	($14,976,046)
Estimated Service Co. VERO add-back costs	$9,447,100
Net VERO savings from Service Co. employees	($5,528,946)
Estimated VERO savings allocated to Narr. O&M	($472,875)

The Narragansett Electric Company
Intrastate Health Care Cost Charged to O & M Adjustment
($000)

		Active Employees	
		Total Company	Intrastate 1/
1	Estimated 2004 health care costs charged to O & M 2/	$4,326	$4,195
2	Estimated VERO related cost savings (O&M) 3/	(599)	(581)
3	Estimated Backfill related costs (O&M) 4/	226	219
4	Adjusted 2004 health care costs through 2004	$3,953	$3,833
5	2005 percentage increase 5/		10.48%
6	2005 increase (line 4 times line 5)		402
7	Total rate year health care costs		$4,235
8	Test Year (2003) health care costs charged to O&M	$4,495	$4,358
9	**Intrastate Health Care Adjustment (line 7 less line 8)**		**($123)**

	Intrastate	Interstate
1/ Interstate Allocation Study, Page 1	96.95%	3.05%

2/ Determination of 2004 Narragansett O&M healthcare costs:

Narragansett total costs (based on 1/01/04 enrollments)	$3,944	
Narragansett O&M % (2003 actual)	79.81%	
		$3,148
Service Co. total costs (based on 1/01/04 enrollments)	$12,250	
Service Co. % Allocation to Narragansett O&M (2003 actual)	9.62%	
		$1,178
Total 2004 Narragansett O&M Health Care		**$4,326**

3/ Estimated VERO impact by company	Cost Reduction	O&M %	Savings
Narragansett (based on VERO enrollments)	$620	79.81%	$495
Service Co. (based on VERO enrollments)	$1,089	9.62%	$105
	Combined VERO Savings		**($599)**

4/ Estimated Backfill adjustment:	Positions	Estimated 2004 Avg Cost/Emp	O&M%	Total
Narragansett	27	$6.7	79.81%	$145
Service Co.	127	$6.6	9.62%	$81
		Combined Backfill Costs		**$226**

5/ Historical increases in Narragansett health care costs per employee:

Narragansett originating and charged (all FERCs):

Year	$ Amount	12 Month Avg # of Employees	$ Per Avg. Employee	Percentage Inc / (Dec)
1998	$2,957	622	$4.8	
1999	$3,145	516	$6.1	28.22
2000	$3,336	628	$5.3	(12.86)
2001	$3,482	664	$5.2	(1.27)
2002	$4,273	607	$7.0	34.23
2003	$4,272	583	$7.3	4.10
Five Year Average				**10.48%**

Notes: Estimated 2004 Avg Cost/Emp= Estimated total $ costs / # of HC enrolled employees @ 1/01/2004
Per Human Resources, current industry projections for 2005 anticipate health care cost increases in the range of 11% to 12.5%

The Narragansett Electric Company
Intrastate Group Insurance Charged to O & M Adjustment
($000)

		Active Employees	
		Total Company	Intrastate
1	12 months ended 12/31/03 Group insurance charged to O & M 1/	$488	$473
2	Adjustment for anticipated VERO savings 3/	($84)	($81)
3	Adjustment for anticipated VERO add-back costs 3/	$29	$28
4	2003 Group insurance costs adjusted for VERO	$433	$420
5	2004 percentage increase 2/		4.50%
6	Increase through 12/31/04 (line 3 times line 4)		$19
7	2004 Group insurance costs (line 3 plus line 5)		$439
8	2005 percentage increase 2/		4.50%
9	Increase through 12/31/2005 (line 6 times line 7)		$20
10	2005 Group Insurance Costs (line 6 plus line 8)		$459
11	Total rate year group insurance costs		$459
12	Test year Group insurance costs (line 3)		$473
13	**Intrastate Group Insurance Adjustment (line 9 less line 10)**		**($14)**

	Intrastate	Interstate
1/ Interstate Allocation Study, Page 1	**96.95%**	**3.05%**

2/ Historical activity for group insurance costs:

Total Group for all Feres-Narragansett:

Year	($000) Total	12 Mth Avg # of Employees	$ Per Avg. Employee	Percentage Inc(Dec)
1998	$389	622	$626	
1999	$470	516	$911	45.47%
2000	$535	628	$851	-6.53%
2001	$560	664	$843	-0.97%
2002	$565	607	$932	10.50%
2003	$402	583	$689	-26.00%
Five-Year Average				**4.50%**

3/ Estimated VERO impact by company:

Cost Savings:	# of Employees	Avg Cost	% Chg to to O&M	Total Costs
Narragansett	120	$689	65.83%	($54,449)
Service Company	226	$689	18.65%	($29,053)
				($83,502)
Add-back costs:				
Narragansett	27	$689	65.83%	$12,251
Service Company	127	$689	18.65%	$16,326
				$28,577

The Narragansett Electric Company
Pension Cost Adjustment
($000)

		3/ Total Company	1/ Intrastate
1	2005 (Rate Year) Pension Expense 2/ (using FY 2005 estimate)	($722)	($700)
2	Test year pension expense/(income) per the books 2/	($403)	($391)
3	Rate year adjustment for pension expense		**($309)**

		Intrastate	Interstate
1/	Interstate Allocation Study, Page 1	**96.95%**	**3.05%**

2/ This amount includes all Narragansett FAS 87 expense and a portion of Service Company expense as follows:

	Total Pension Costs ($000) NECO	SVCCo	Total
2003 FAS 87 Cost	($1,436)	$3,235	
Percentage charged to NECO's O & M	67.27%	17.41%	
Total Company 2003 pension cost to NECO's O & M	($966)	$563	($403)
Rate year Estimated FAS 87 Cost 3/	**($1,815)**	**$2,867**	
Percentage charged to NECO's O & M	67.27%	17.41%	
Total Company Rate year pension cost to NECO's O & M	($1,221)	$499	($722)

3/ Based on most recent actuarial estimate

The Narragansett Electric Company
Post-retirement Benefit Cost Adjustment
($000)

		3/ Total Company	1/ Intrastate
1	2005 (Rate Year) Post-retirement benefits expense 2/ (using FY 2005 estimate)	$7,848	$7,609
2	Test year post-retirement benefits expense per the books 2/	$8,981	$8,707
3	Rate year adjustment for post-retirement benefits expense		**($1,098)**

		Intrastate	Interstate
1/	Interstate Allocation Study, Page 1	**96.95%**	**3.05%**

2/ This amount includes all Narragansett FAS 106 expense and a portion of Service Company expense as follows:

	Total Pension Costs ($000) NECO	SVCCo	Total
2003 FAS 106 Cost	$9,231	$13,788	
Percentage charged to NECO's O & M	80.27%	11.39%	
Total Company 2003 FAS 106 cost to NECO's O & M	$7,410	$1,571	
2003 FAS 106 expense normalizations	$0	$0	
2003 FAS 106 expense	$7,410	$1,571	$8,981
Rate Year Estimated FAS 106 Cost 3/	**$8,394**	**$9,744**	
Percentage charged to NECO's O & M	80.27%	11.39%	
Total Company Rate Year FAS 106 cost to NECO's O & M	$6,738	$1,110	$7,848

3/ Based on most recent actuarial estimate

The Narragansett Electric Company

Inflation Adjustment

($000)

Line		Total Company Per Books	Interstate	Intrastate
1	Operation & Maintenance Expense 1/	$131,002	$2,753	$128,249
2				
3	Salaries & Wages charged to O & M	($24,569)	($1,023)	($23,546)
4	Net Salaries & Wages adj. due to VERO savings from Svc Co.allocations	($473)	($20)	($453)
5	Health Care Costs charged to O & M (Active Employees)	($4,495)	($137)	($4,358)
6	Group Insurance charged to O&M (Active Employees)	($488)	($15)	($473)
7	Pensions	$403	$12	$391
8	FAS 106	($8,981)	($274)	($8,707)
9	Incremental NIMO Integration Expenses	($4,210)	($766)	($3,444)
10	2003 Bad Debt Expense	($5,410)	$0	($5,410)
11	Advertising Expense & Other Non-Recoverable Expense	($183)	($6)	($177)
12	Storm Fund	($1,041)	$0	($1,041)
13	Non-recurring test year Expense	($2,000)	($61)	($1,939)
14	VERO adjustment	($25,122)	($765)	($24,357)
15	Environmental Response Fund	($3,078)	$0	($3,078)
16	Out of Period Expenses	($1,448)	$0	($1,448)
17	2003 Subtotal			$50,208
18				
19	Inflation for 2004 - Line 17 x 1.21% 2/			$608
20				
21	Adjusted balance 2004			$50,816
22				
23	Inflation for 2005 - Line 21 x 1.32% 2/			$672
24				
25	Adjusted balance 2005			$51,488
26				
27				
28	**Rate Year Inflation Adjustment**			
29				
30	2004 Adjusted Balance (Line 23)			$51,488
31	Less: Unadjusted Balance test year			$50,208
32	**Rate Year Inflation Adjustment**			**$1,280**
33				

1/ Page 1

2/ Inflation Rate : Average of quarterly changes in estimated GDP Chained Price Index as published by Economy.com

Avg change in GDP Chained Price Index - 2003	1.65%
Avg change in GDP Chained Price Index - 2004	1.21%
Avg change in GDP Chained Price Index - 2005	1.32%

The Narragansett Electric Company

Intrastate Depreciation Expense Adjustment

($000)

	Total Company Rate Year	Production	Interstate Transmission	Intrastate Transmission	Distrib	General	PHFFU	Total
1	Total Company Rate Year Depreciation Expense	$258	$3,584	$745	$32,717	$2,381	$0	$39,685
2	Total Company Test Year Depreciation Expense	$258	$3,187	$704	$30,279	$2,314	$0	$36,742
3		$0	$397	$41	$2,438	$67	$0	$2,943
4								
5	Interstate % 1/	0.00%	100.00%	0.00%	0.72%	14.52%	100.00%	
6	Less Interstate Allocation	$0	$397	$0	$18	$10	$0	$425
7								
8	**Intrastate Depreciation Expense Adjustment**	$0	$0	$41	$2,420	$57	$0	$2,518
9								
10			Interstate	Intrastate				
11		Other	< 345KV	< 345KV				
12	**2003 Depreciation Expense**	Production	Transmission	Transmission	Distrib	General	PHFFU	Total
13								
14	Total Utility Plant 12/31/03	$3,126	$148,660	$32,629	$882,380	$58,429	$12,707	$1,137,932
15	Less Non Depreciable Plant (Oct 03 amts)	$7	$4,430	$4,179	$8,007	$976	$12,707	$30,306
16	Depreciable Utility Plant 12/31/03	$3,119	$144,229	$28,451	$874,373	$57,453	$0	$1,107,626
17								
18	Composite Book Rate %	8.27%	2.31%	2.31%	3.53%	4.04%	0.00%	
19								
20	Book Depreciation Reserve 12/31/03	$2,425	$49,863	$11,020	$337,132	$16,181	$0	$416,621
21								
22	**2004 Depreciation Expense**							
23		0.28%	13.21%	2.90%	78.42%	5.19%		
24	Total Utility Plant 1/1/04	$3,126	$148,660	$32,629	$882,380	$58,429	$12,707	$1,137,932
25	Less Non Depreciable Plant	$7	$4,430	$4,179	$8,007	$976	$12,707	$30,306
26	Depreciable Utility Plant 1/1/04	$3,119	$144,229	$28,451	$874,373	$57,453	$0	$1,107,626
27	Plus: Added Plant	$0	$6,348	$1,252	$38,450	$1,450	$0	$47,500
28	Less: Added Non Depreciable Plant	$0	$0	$0	$0	$0	$0	$0
	Dep Retired Plant	$0	$542	$107	$6,148	$787	$0	$7,583
1	Depreciable Utility Plant 12/31/04	$3,119	$150,035	$29,596	$906,675	$58,117	$0	$1,147,543
2	Weighted Average Plant	$3,119	$147,132	$29,023	$890,524	$57,785	$0	$1,127,584
3	Composite Book Rate % 2/	8.27%	2.31%	2.31%	3.53%	4.04%	0.00%	
4								
5	Book Depreciation Reserve 1/1/04	$2,425	$49,863	$11,020	$337,132	$16,181	$0	$416,621
6	Plus: Book Depreciation Expense	$258	$3,399	$670	$31,435	$2,335	$0	$38,097
7	Salvage	$0	$0	$0	$0	$0	$0	$0
8	Highway Reimbursements	$0	$0	$0	$1,277	$0	$0	$1,277
9	Less: Retired Plant	$0	$542	$107	$6,148	$787	$0	$7,583
10	Net Cost of Removal/(Salvage)	$0	$321	$63	$1,763	$352	$0	$2,499
11	Book Depreciation Reserve 12/31/04	$2,683	$52,399	$11,520	$361,934	$17,377	$0	$445,913
12								
13	**2005 Depreciation Expense**							
14								
15	Total Utility Plant 1/1/05	$3,126	$154,466	$33,775	$914,682	$59,092	$12,707	$1,177,848
16	Less Non Depreciable Plant	$7	$4,430	$4,179	$8,007	$976	$12,707	$30,306
17	Depreciable Utility Plant 1/1/05	$3,119	$150,035	$29,596	$906,675	$58,117	$0	$1,147,542
18	Plus: Added Plant	$0	$6,348	$1,252	$38,450	$1,450	$0	$47,500
19	Less: Added Non Depreciable Plant	$0	$0	$0	$0	$0	$0	$0
20	Dep Retired Plant	$0	$542	$107	$6,148	$787	$0	$7,583
21	Depreciable Utility Plant 12/31/05	$3,119	$155,842	$30,741	$938,976	$58,780	$0	$1,187,459
22	Weighted Average Plant	$3,123	$155,154	$32,258	$926,829	$58,936	$6,354	$1,182,653
23	Composite Book Rate % 2/	8.27%	2.31%	2.31%	3.53%	4.04%	0.00%	
24								
25	Book Depreciation Reserve 1/1/05	$2,683	$52,399	$11,520	$361,934	$17,377	$0	$445,913
26	Plus: Book Depreciation Expense	$258	$3,584	$745	$32,717	$2,381	$0	$39,686
27	Salvage	$0	$0	$0	$0	$0	$0	$0
28	Highway Reimbursements	$0	$0	$0	$1,277	$0	$0	$1,277
29	Less: Retired Plant	$0	$542	$107	$6,148	$787	$0	$7,583
30	Net Cost of Removal/(Salvage)	$0	$321	$63	$1,763	$352	$0	$2,499
31	Book Depreciation Reserve 12/31/05	$2,941	$55,442	$12,158	$388,503	$18,971	$0	$476,794
32								
33								

1/ Interstate Allocation Study, Page 1

2/ Per 2002 Ferc Form 1, pages 205-207, 336

The Narragansett Electric Company
Intrastate Municipal Tax Adjustment
($000)

		Total Company Per Books	Interstate	Intrastate
1	Test Year Municipal Taxes - 12 MTD 12/31/03	$20,274	$3,141 1/	$17,133
2				
3	Estimated Municipal Taxes for 2005 (from Property Tax)	$21,245	$3,291	$17,954
4				
5	**Intrastate Municipal Tax Adjustment**			**$821**

1/ Interstate Allocation Study, Page 1

The Narragansett Electric Company
Intrastate FICA Adjustment
($000)

		Total Company Per Books	Interstate and Other	Intrastate
1	FICA 12 months ended 12/31/03- Test Year	$3,424	$104 1/	$3,320
2	FICA Percentage change- Rate Year			-0.42%
3	**Intrastate FICA Adjustment**			**($14)**

1/ Interstate Allocation Study, Page 1

2/ Salary and Wage Increase:

	Total	Percentage Inc(Dec)
Test Year O&M Wages - Ferc Form 1 P 355	$24,569	---
Rate Year O&M Wages 1/1/05-12/31/05	$24,466	-0.42%

The Narragansett Electric Company
Intrastate Rate Base
($000)

		5 Quarter Average				
		Total Company 12/31/03	Interstate and Other 12/31/03 1/	Intrastate 12/31/03	Adjustments	Rate Year Intrastate Rate Base
1	Utility Plant in Service	$1,104,893	$160,425	$944,468	$67,907	$1,012,376
2	Property Held for Future Use	$12,707	$12,707	$0	$0	$0
3	Total Utility Plant	$1,117,600	$173,132	$944,468	$67,907	$1,012,376
4						
5	Less - Reserve for Depreciation	($404,694)	($53,125)	($351,569)	($50,711)	($402,281)
6						
7	Plus - Loss on Reacquired Debt	$10,649	$1,546	$9,103	($914)	$8,189
8						
9	- Materials & Supplies	$4,721	$685	$4,035	$277	$4,312
10						
11	- Prepayments	$156	$23	$133	($143)	($9)
12						
13	Less - Uninsured Claims Liability	$0	$0	$0	$0	$0
14						
15	- Customer Deposits	($2,602)	$0	($2,602)	$609	($1,993)
16						
17	- Reserve for Deferred FIT	($68,661)	($30,519)	($99,179)	($7,892) 2/	($107,071)
18						
19	Rate Base before Cash Working Capital	$657,169		$504,389		$513,523
20						
21	Plus - Cash Working Capital	-		-		$19,077
22						
23	**Intrastate Rate Base**					**$532,600**

1/ Interstate Allocation Study, Page 1
2/ Assumes $15,935k of additional tax Depreciation for CY 2004.

The Narragansett Electric Company
5 Quarter Average Intrastate
Utility Plant in Service
($000)

Line			Prod.	Interstate Trans.	Intrastate Trans.	Distr.	General	Future Use	Total
1	Balance @ December 31, 2003		$3,126	$148,660	$32,629	$882,380	$58,429	$12,707	$1,137,932
2									
3									
4	Plus: Plant Additions for 2004		$0	$6,348	$1,252	$38,450	$1,450	$0	$47,500
5	Less: Plant Retirements		$0	($532)	($117)	($6,154)	($787)	$0	($7,591)
6									
7									
8	Balance	12/31/04	$3,126	$154,475	$33,765	$914,676	$59,092	$12,707	$1,177,841
9									
10		1/31/05 1/	$3,126	$154,960	$33,859	$917,367	$59,147	$12,707	$1,181,167
11		2/28/05	$3,126	$155,444	$33,954	$920,059	$59,202	$12,707	$1,184,493
12		3/31/05	$3,126	$155,929	$34,048	$922,750	$59,258	$12,707	$1,187,818
13		4/30/05	$3,126	$156,413	$34,143	$925,441	$59,313	$12,707	$1,191,144
14		5/31/05	$3,126	$156,898	$34,238	$928,133	$59,368	$12,707	$1,194,470
15		6/30/05	$3,126	$157,383	$34,332	$930,824	$59,423	$12,707	$1,197,796
16		7/31/05	$3,126	$157,867	$34,427	$933,515	$59,479	$12,707	$1,201,121
17		8/31/05	$3,126	$158,352	$34,521	$936,206	$59,534	$12,707	$1,204,447
18		9/30/05	$3,126	$158,836	$34,616	$938,898	$59,589	$12,707	$1,207,773
19		10/31/05	$3,126	$159,321	$34,711	$941,589	$59,644	$12,707	$1,211,099
20		11/30/05	$3,126	$159,806	$34,805	$944,280	$59,700	$12,707	$1,214,424
21		12/31/05	$3,126	$160,290	$34,900	$946,972	$59,755	$12,707	$1,217,750
22									
23	5 Quarter Average		$3,126	$157,383	$34,332	$930,824	$59,423	$12,707	$1,197,796
24									
25	Interstate Allocating Factors 2/		0.00%	100.00%	0.00%	0.72%	14.52%	100.00%	-
26									
27	Interstate Utility Plant in Service		$0	$157,383	$0	$6,702	$8,628	$12,707	$185,420
28									
29	Intrastate Utility Plant in Service		$3,126	($0)	$34,332	$924,122	$50,795	$0	$1,012,376

	Prod.	Interstate Transm.	Intrastate Transm.	Distr.	General	Future Use	Total
1/ 2005 Plant Detail:							
Plant Additions	$0	$6,348	$1,252	$38,450	$1,450	$0	$47,500
Plant Retirements	$0	($532)	($117)	($6,154)	($787)	$0	($7,591)
Net Increase (decrease)	$0	$5,815	$1,135	$32,296	$663	$0	$39,909
Monthly Amount	$0	$485	$95	$2,691	$55	$0	$3,326

2/ Interstate Allocation Study, Page 1

The Narragansett Electric Company
5 Quarter Average Intrastate
Reserve for Depreciation
($000)

		Prod.	Interstate Transm.	Intrastate Transm.	Distr.	General	Future Use	Total
1	Balance @ December 31, 2003	($2,425)	($49,863)	($11,020)	($337,132)	($16,181)	$0	($416,621)
2								
3								
4	Depreciation 1/1/04 - 12/31/04	($258)	($3,399)	($670)	($31,435)	($2,335)	$0	($38,097)
5	Plus: Salvage	$0	$0	$0	$0	$0	$0	$0
6	Highway Reimbursements	$0	$0	$0	($1,277)	$0	$0	($1,277)
7	Less: Retirements	$0	$542	$107	$6,148	$787	$0	$7,583
8	Net Cost of Removal/(Salvage)	$0	$321	$63	$1,763	$352	$0	$2,499
9								
10	Balance 12/31/04	($2,683)	($52,399)	($11,520)	($361,934)	($17,377)	$0	($445,913)
11								
12	1/31/05 1/	($2,704)	($52,626)	($11,568)	($364,108)	($17,481)	$0	($448,487)
13	2/28/05	($2,726)	($52,853)	($11,616)	($366,281)	($17,584)	$0	($451,060)
14	3/31/05	($2,747)	($53,080)	($11,664)	($368,455)	($17,688)	$0	($453,633)
15	4/30/05	($2,769)	($53,307)	($11,712)	($370,629)	($17,791)	$0	($456,207)
16	5/31/05	($2,790)	($53,533)	($11,760)	($372,802)	($17,895)	$0	($458,780)
17	6/30/05	($2,812)	($53,760)	($11,808)	($374,976)	($17,998)	$0	($461,354)
18	7/31/05	($2,833)	($53,987)	($11,856)	($377,149)	($18,102)	$0	($463,927)
19	8/31/05	($2,855)	($54,214)	($11,903)	($379,323)	($18,205)	$0	($466,500)
20	9/30/05	($2,876)	($54,440)	($11,951)	($381,497)	($18,309)	$0	($469,074)
21	10/31/05	($2,898)	($54,667)	($11,999)	($383,670)	($18,412)	$0	($471,647)
22	11/30/05	($2,919)	($54,894)	($12,047)	($385,844)	($18,516)	$0	($474,221)
23	12/31/05	($2,941)	($55,121)	($12,095)	($388,018)	($18,620)	$0	($476,794)
24								
25	5 Quarter Average	($2,812)	($53,760)	($11,808)	($374,976)	($17,998)	$0	($461,354)
26								
27	Interstate Allocating Factors 2/	0.00%	100.00%	0.00%	0.72%	14.52%	100.00%	
28								
29	Interstate Depreciation Reserve	$0	($53,760)	$0	($2,700)	($2,613)	$0	($59,073)
30								
31	**Intrastate Depreciation Reserve**	**($2,812)**	**($0)**	**($11,808)**	**($372,276)**	**($15,385)**	**$0**	**($402,281)**

1/ 2004 Depreciation Reserve Detail	Prod.	Interstate Transm.	Intrastate Transm.	Distr.	General	Future Use	Total
Depreciation Expense	($258)	($3,584)	($745)	($32,717)	($2,381)	$0	($39,686)
Plus: Salvage	$0	$0	$0	$0	$0	$0	$0
Highway Reimbursements	$0	$0	$0	($1,277)	$0	$0	($1,277)
Less: Retirements	$0	$542	$107	$6,148	$787	$0	$7,583
Cost of Removal	$0	$321	$63	$1,763	$352	$0	$2,499
Net Increase	($258)	($2,721)	($575)	($26,084)	($1,243)	$0	($30,881)
Monthly Increase	($22)	($227)	($48)	($2,174)	($104)	$0	($2,573)

2/ Interstate Allocation Study, Page 1

The Narragansett Electric Company
Intrastate Rate Base Adjustments
($000)

			Unamortized Loss on Reacquired Debt	Materials and Supplies	Prepayments	Uninsured Claims	Customer Deposits
1	Balance @	12/31/03	10,293	5,159	(10)	0	(2,465)
2							
3	2004 Inc/(Dec)		(712)	(76)	0	0	315
4							
5	Balance @	12/31/04	9,581	5,083	(10)	0	(2,150)
6							
7							
8		1/31/05	9,522	5,077	(10)	0	(2,124)
9		2/28/05	9,462	5,071	(10)	0	(2,098)
10		3/31/05	9,403	5,064	(10)	0	(2,072)
11		4/30/05	9,344	5,058	(10)	0	(2,046)
12		5/31/05	9,284	5,052	(10)	0	(2,019)
13		6/30/05	9,225	5,045	(10)	0	(1,993)
14		7/31/05	9,166	5,039	(10)	0	(1,967)
15		8/31/05	9,106	5,033	(10)	0	(1,941)
16		9/30/05	9,047	5,026	(10)	0	(1,914)
17		10/31/05	8,988	5,020	(10)	0	(1,888)
18		11/30/05	8,928	5,014	(10)	0	(1,862)
19		12/31/05	8,869	5,007	(10)	0	(1,836)
20							
21	5 Quarter Avg.		9,225	5,045	(10)	0	(1,993)
22							
23	Interstate % 1/		14.52%	14.52%	14.52%	0.00%	0.00%
24							
25	Interstate		1,339	733	(1)	0	0
26							
27	**Intrastate**		**7,886**	**4,312**	**(9)**	**0**	**(1,993)**
	Changes:						
	Annual		(712) 2/	(76) 3/	0 4/	0 4/	315 3/
	Monthly		(59)	(6)	0	0	26

1/ Interstate Allocation Study
2/ Monthly adjustments reflect amortization at settlement level
3/ Adjustment based on average annual change for the prior 3 years
4/ Assume no change in 2003 balance

The Narragansett Electric Company
Intrastate Current Federal Income Taxes
($000)

						Intrastate
1	Overall Return 1/	$532,600	x	8.89%		$47,348
2	Interest 1/	$532,600	x	3.41%		($18,162)
3	Book Income					$29,186
4						
5						
6	**PLUS: Book Expenses Not Deductible**					
7	**for Tax Purposes**					
8						
9	Deferred Tax Expense					$2,276
10	Flow through items					$226
11	50% of Business Meals					$0
12	Storm Contingency Fund Expense					$0
13	Amortization of Loss on Reacquired Debt					$609
14						
15	**LESS: Book Income Not Taxable**					
16						
17	Investment Tax Credit Amortization					$717
18						
19	**LESS: Tax Deductions Not Recorded**					
20	**on the Books**					
21						
22	Additional Tax Depreciation					$3,141
23	Cost of Removal Tax Deduction					$2,114
24	Storm Contingency Fund					$0
25	Preferred Dividends Paid Deduction					$0
26	Taxable Income Base (TIB)					$26,325
27						
28	Taxable Income (TI=TIB/(1-0.35))					$40,500
29						
30	**Intrastate Current Federal Income Tax (TI x .35)**					$14,175
31						
32	Total Deferred Tax Expense (lines 9 above)					$2,276
33						
34	**Total Current and Deferred Federal Income Tax**					**$16,451**

1/ From Pages 13 and 20
All new originating book tax timing differences are fully normalized on the books for Federal tax purposes. Therefore, these deferred taxes and their related timing differences are not shown.

The Narragansett Electric Company

Intrastate Deferred Federal Income Tax Expense

$000

	Generation	Total Company	Less Interstate	Intrastate
1	Liberalized Depreciation - net	1,286	187	1,099
2	(CIAC)	0	0	0
3	Cost of Removal	875	135	740
4	Unfunded Catch-up 1/	650	0	650
5				
6	Reversal			
7				
8	Liberalized Depreciation	0	0	0
9	(CIAC)	0	0	0
10	Storm Contingency Fund Expense	0	0	0
11	Amortization of Loss on Reacquired Debt	(249)	(36)	(213)
12				
13	**Net Deferred Federal Income Taxes**	2,562	285	2,276

1/ See Page 19 (line 51)

The Narragansett Electric Company
Unfunded Deferred Federal Income Taxes
($000s)

1	Book Depreciable Plant at 12/31/98		$713,405		
2	Less: Accumulated Depreciation		(209,159)		
3	Permanent book/tax differences				
4	Equity AFUDC		(1,489)		
5	ITC Basis Adjustment		(1,689)		
6	Adjusted net plant per books			$501,068	
7					
8	Tax Depreciable Plant		701,399		
9	Less: Accumulated depreciation		(406,543)		
10	Adjusted net tax plant			294,856	
11					
12	Cumulative Timing Difference			206,212	
13	Current Tax Rate			35.0%	
14					
15	Total Cumulative Deferred Federal Tax Liability			$72,174	
16					
17	Property Related Deferred FIT Reserves per Books at 12/31/98:				
18					
19	Contributions in Aid of Construction		(2,408)		
20	Liberalized Depreciation		55,012		
21	Construction Interest		(1,166)		
22	Construction - Other		(11)		
23	Cost of Removal		2,591		
24	ACRS Retirements		1,560		
25	Transfer Accounts		(1,340)		
26	Unfunded Tax Liability		38		
27	Total			$54,275	
28					
29	Unfunded Property-Related Deferred FIT Reserves				$17,899
30					
31	Non- Property Related Deferred FIT Reserves per Books at 12/31/98:				
32				Unfunded/	
33		Bal. per Books	Bal. @ 35%	(Excess)	
34	Deferred Tax Assets	(14,694)	(15,360)	(666)	
35	Deferred Tax Liabilities	10,287	14,751	4,464	
36					
37					
38	Unfunded Non Property-Related Deferred FIT Reserves				3,798
39					
40	Total Unfunded Deferred FIT Reserves @ 12/31/99				$21,697
41					
42	Blackstone Valley Electric Unfunded @ 12/31/99				$1,386
43	Newport Electric Unfunded @ 12/31/99				$1,630
44					
45	Total Unfunded @ 12/31/99				$24,713
46					
47	Funded with CTC Refunds and Delay Credit [(17,500 + 5,000 + 500) * 65%				($14,950)
48					
49	Remaining Unfunded Deferred Taxes				$9,763
50					
51	Allowed Annual Recovery				$650
52					
53	Recovery Period - Years				15.02
54					
55					

The Narragansett Electric Company
Total Company Capital Structure and Cost of Capital
($000)

		Capital Structure (a)	Cost Rate (b)	Weighted Return	Taxes	Pre-tax Return
1	Long Term Debt	45.00%	7.57%	3.41%		3.41%
2						
3	Preferred Stock	5.00%	4.58%	0.23%	0.12%	0.35%
4						
5	Total Common Equity	50.00%	10.50%	5.25%	2.83%	8.08%
6						
7	Total Capitalization	100.00%		8.89%	2.95%	11.84%

(a) Per Third Amended Stipulation and Settlement dated March 14, 2000.
(b) Reflects actual 2003 cost rates for Long Term Debt and Preferred Stock and ROE rate from Third Amended Stipulation and Settlement dated March 14, 2000.

The Narragansett Electric Company
Intrastate Cash Working Capital
($000)

	Rate Year Intrastate Amount		Lead/Lag Percent	Rate Year Intrastate Cash Working Capital
Operation & Maintenance Expense	$98,349	1/	7.86%	$7,730
Purchased Power and Transmission Expense	512,039	2/	1.79%	9,165
Federal Income Tax - Current	14,175		-0.17%	-24
Taxes Other Than Income Taxes				
Municipal Taxes	17,954	1/	5.94%	1,066
Sales and Use Tax	13,505	2/	0.70%	95
Gross Earnings Tax	7,714		12.37%	954
Payroll Taxes - Company Portion				
Federal Unemployment	42	1/	-16.76%	-7
State Unemployment	184	1/	-14.65%	-27
FICA - Weekly 1/	2,195	4/	9.35%	205
FICA - Monthly 1/	1,111	4/	9.62%	107
Payroll Withheld				
FICA and Federal Withholding - Wee	5,928	3/	-0.74%	-44
FICA and Federal Withholding - Montl	3,005	3/	-0.47%	-14
R.I. Income Tax - Weekly	1,062	3/	-0.73%	-8
R.I. Income Tax - Monthly	569	3/	-0.47%	-3
Temporary Disability Inc. - Weekly	307	3/	-21.86%	-67
Temporary Disability Inc. - Monthly	97	3/	-20.74%	-20
Incentive Thrift - Weekly	2,326	3/	-0.95%	-22
Incentive Thrift - Monthly	1,011	3/	-0.86%	-9
Total Intrastate Cash Working Capital Requirement	$681,573			$19,077

1/ page 1

2/ Per books 2003 less interstate total O&M allocator MDL-2,P1 1.45%

3/ Per books 2003 less interstate total P/R allocator MDL-2 P5 4.17%

4/	Total '03 FICA Witholding	% to Total	Wkly/Mnthly FICA Alloc
FICA Monthly	$3,135	33.60%	$1,111
FICA Weekly	$6,185	66.40%	$2,195
	$9,320	100.00%	$3,306

Commission Data Request 1-92

Request:

Please provide the rationale for basing the Calculation of Distribution Rate Reduction on a forecasted benchmark COS rather than actual forecasted cost of service for 2005?

Response:

The calculation of the Distribution Rate Reduction of $10,243,000 on Exhibit 1 to the Settlement is based on the comparison between the Forecasted Revenue-2005 under current rates of $230,847,000 shown on line 1 of Exhibit 1 less the Cost of Service including Shared Savings of $220,604,000 shown on line 7 of that Exhibit. The benchmark COS is not used to calculate the rate reduction; it is only used to calculate the amount of savings to be shared. This amount is determined by comparing the agreed upon cost of service of $215,604,000 shown on line 2 to the Forecast Benchmark COS 2005 of $225,604,000. Under the Settlement, customers were provided their $5.0 million share of these savings up front in the form of a rate reduction for five years. Narragansett's share was adjusted to $4.645 million and is subject to the risk that it can actually operate its business at the agreed upon cost of service over the next five years.

Specifically, because the proposed earnings sharing mechanism is applied only to earnings in excess of 10.50%, the Company has assumed the risk that it can operate its distribution business at the settled cost level of $215.6 million in order to earn its $4.645 million share of savings. Therefore, Narragansett has the incentive to generate the efficiencies required to achieve that level of cost during the rate freeze period. If the Company cannot operate its distribution business at that cost level, it will not earn its full share of merger savings. For example, if in 2005, the Company operates its distribution business (excluding shared savings) at a cost level of $220.4 million (see the 2005 cost of service provided with the response to Commission Data Request 1-91), at the proposed Settlement rate level of $220.6 million, it would earn only $200,000 of shared savings ($220.6 million minus $220.4 million). On the other hand, customers will see their full $5.0 million share of their shared savings amount in each year of the Rate Freeze as part of the $10.243 million base rate reduction, regardless of the Company's ability to generate additional efficiencies during the period. For these reasons, the settling Parties agreed that the calculation of the distribution rate reduction provided an equitable balance of immediate and long term customer benefits with Company risk and opportunity consistent with an incentive-based rate plan.

Prepared by or under the supervision of: Legal Department

Commission Data Request 1-93

Request:

Referring to Exhibit 1, line 1, please provide a supporting schedule for the derivation of $230,847,000.

Response:

The forecasted revenue for 2005 shown on line 1 of Exhibit 1, page 1 of 3, consists of $225,847,000 of normalized rate year revenue and approximately $5,000,000 of other distribution revenue. Please refer to the attached schedules which support the derivation of the normalized rate year revenues of $230,847,000.

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

The Narragansett Electric Company
Summary of Rate Year 2005 Normalized Revenues

	Rate Year Number of Bills (a)	Calculated Customer Charge Rev (b)	Prorate Factor (c)	Normalized Customer Charge Rev (d)	Rate Year Billing Demand (e)	Calculated Demand Charge Rev (f)	Prorate Factor (g)	Normalized Demand Charge Rev (h)	2005 Forecasted Rate Class kWhs (i)	Normalized Energy Charge Rev (j)	2005 Normalized Total Rev (1) (k)
A16	4,393,558	$11,159,637	0.29%	$11,192,140	0	$0	-	$0	2,433,840,000	$88,640,453	$99,832,592
A18	235,682	$593,919	0.53%	$597,076	0	$0	0.00%	$0	207,500,000	$6,413,390	$7,010,466
A32	29,741	$68,404	0.88%	$69,007	0	$0	0.00%	$0	80,910,000	$2,173,885	$2,242,892
A60	370,904	$0	0.00%	$0	0	$0	0.00%	$0	180,490,000	$4,080,383	$4,080,383
A62	14,101	$0	0.00%	$0	0	$0	0.00%	$0	11,590,000	$217,170	$217,170
B62	24	$410,849	2.73%	$422,055	377,874	$283,405	0.00%	$283,405	218,550,000	$795,040	$1,500,501
C06	511,707	$2,918,232	0.88%	$2,943,781	0	$0	0.00%	$0	525,930,000	$20,300,898	$23,244,679
E30	158	$1,191	-0.69%	$1,183	0	$0	0.00%	$0	1,770,000	$28,001	$29,185
E40	185	$13,903	1.47%	$14,108	0	$0	0.00%	$0	7,680,000	$114,676	$128,784
G02	82,592	$8,540,839	-0.28%	$8,517,313	3,885,576	$8,903,598	0.89%	$8,982,597	1,113,000,000	$11,018,590	$28,518,500
G22	29,827	$0	0.00%	$0	1,194,815	$1,792,222	0.64%	$1,803,622	361,170,000	$7,991,537	$9,795,159
G32	12,160	$2,874,989	-0.32%	$2,865,874	5,851,130	$9,127,762	0.38%	$9,162,134	2,138,610,000	$22,610,944	$34,638,952
G62	132	$2,259,671	-1.49%	$2,226,065	651,131	$488,348	1.42%	$495,264	315,690,000	$1,002,049	$3,723,377
M1	36	$0	0.00%	$0	0	$0	0.00%	$0	798,000	$126,000	$126,000
N01	12	$205,425	0.00%	$205,425	223,129	$167,347	0.00%	$167,347	119,720,000	$371,763	$744,535
R02	7,368	$0	0.00%	$0	0	$0	0.00%	$0	4,450,000	$38,582	$38,582
S10	-	$1,037,129	-0.22%	$1,034,871	0	$0	0.00%	$0	11,379,997	($211,322)	$823,549
S12	2,000	$5,469,521	0.15%	$5,477,583	0	$0	0.00%	$0	38,250,215	$151,471	$5,629,054
S14	2,787	$3,118,030	0.44%	$3,131,779	0	$0	0.00%	$0	19,748,559	($443,245)	$2,688,534
T-Res	2,197	$17,222	-0.77%	$17,090	0	$0	0.00%	$0	8,910,119	$200,210	$217,301
T-Comm	844	$6,619	-0.77%	$6,569	0	$0	0.00%	$0	8,329,881	$187,172	$193,741
V02	2,498	$19,609	-0.23%	$19,565	0	$0	0.00%	$0	6,170,000	$187,445	$207,009
X01	12	$120,000	0.00%	$120,000	0	$0	0.00%	$0	26,230,000	$103,871	$223,871
	5,698,525	$38,835,190.09		$38,861,482	12,183,654	$20,762,683		$20,894,369	7,840,716,771	$166,098,964	$225,854,814

(1) Variance of approximately $8,000 from Exhibit 1, Page 1 of 3, Line 1 due to correction of error in calculation of Rate G-32 normalized revenues.

(a) per Company forecast
(b) Pages 2 - 8
(c) RIPUC Docket No. 3610, Schedule JAL-4, Page 1 of 1
(d) column (b) x (1 + column (c))
(e) per Company forecast
(f) Pages 2 - 8
(g) RIPUC Docket No. 3610, Schedule JAL-4, Page 1 of 1
(h) column (f) x (1 + column (g))
(i) per Company forecast
(j) Pages 2 - 8
(k) column (d) + column (h) + column (j)

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The Narragansett Electric Company
Rate Year Normalized Revenues

Rate Class/Description (1)	Description of Charges (2)	Units (3)	Rate (4)	Revenues (5)
A-16 * Residential	Customer Charge	4,393,558	$2.54	$11,159,637.32
	Distribution kWh Charge	2,433,840,000	$0.03642	$88,640,452.80
	Total Distribution Revenue			$99,800,090.12
A-18 Residential Controlled Water Heating	Customer Charge	235,682	$2.52	$593,918.64
	Distribution kWh Charge	207,500,000	$0.03536	$7,337,200.00
	Water Heating Credit (1st 750) (1)	139,759,426	($0.00661)	($923,809.81)
	Subtotal Distribution kWh Charges			$6,413,390.19
	Total Distribution Revenue			$7,007,308.83
	(1) Estimated as 593 kWhs (2003 actual average use for block) times Number of bills			
A-60 Residential Low Income	Customer Charge	370,904	$0.00	$0.00
	Distribution kWh Charge	180,490,000	$0.02551	$4,604,299.90
	BVE - 1st 300 kWh Charge	21,318,134	($0.01436)	($306,128.40)
	BVE - In excess of 300 kWh Charge	13,591,357	$0.01194	$162,280.80
	Newport - 1st 300 kWh Charge	3,327,252	($0.00782)	($26,019.11)
	Newport - In excess of 300 kWh Charge	2,851,543	$0.01952	$55,662.12
	Low Income Credit	180,490,000	($0.00227)	($409,712.30)
	Total Distribution Revenue			4,080,383.00
52 sidential Low Income with Controlled Water Heating	Customer Charge	14,101	$0.00	$0.00
	Distribution kWh Charge	11,590,000	$0.02551	$295,660.90
	Water Heating Credit (1st 750)	8,136,277	($0.00661)	($53,780.79)
	BVE - 1st 300 kWh Charge	277,667	($0.01436)	($3,987.30)
	BVE - In excess of 300 kWh Charge	262,821	$0.01194	$3,138.08
	Newport - 1st 300 kWh Charge	479,842	($0.00782)	($3,752.37)
	Newport - In excess of 300 kWh Charge	317,665	$0.01952	$6,200.82
	Low Income Credit	11,590,000	($0.00227)	($26,309.30)
	Total Distribution Revenue			217,170.04
	(1) Water Heating Credits from SMB702 data file; kWhs calculated by dividing revenues by credit.			
A-32 Residential Time-of-Use	Customer Charge	29,741	$2.30	$68,404.30
	Meter Charge	23,470	$4.44	$104,206.80
	Distribution kWh Charge	80,910,000	$0.02558	$2,069,677.80
	Total Distribution kWh Charge			$2,173,884.60
	Total Distribution Revenue			$2,242,288.90
E-30 Residential Storage Heat	Customer Charge	158	$7.54	$1,191.32
	Distribution kWh Charge	1,770,000	$0.01582	$28,001.40
	Total Distribution Revenue			$29,192.72

Column (3): per Company forecast
Column (4) per current tariffs; kWh charges include Settlement credit of $0.00038 per kWh
Column (5): Column (3) times Column (4)

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The Narragansett Electric Company
Rate Year Normalized Revenues

Rate Class/Description (1)	Description of Charges (2)		Units (3)	Rate (4)	Revenues (5)
T-06 Limited All-Electric Living - Residential	Customer Charge		2,197	$7.84	$17,222.13
	Distribution kWh Charge		8,910,119	$0.02247	$200,210.37
	Total Distribution Revenue				$217,432.50
T-06 Limited All-Electric Living - Commercial	Customer Charge		844	$7.84	$6,619.31
	Distribution kWh Charge		8,329,881	$0.02247	$187,172.43
	Total Distribution Revenue				$193,791.74
C-06 Small C&I	Customer Charge		508,156	$5.73	$2,911,733.88
	Unmetered Charge		3,551	$1.83	$6,498.33
	Total Customer Charge				$2,918,232.21
	Distribution kWh Charge		525,930,000	$0.03860	$20,300,898.00
	Total Distribution kWh Charge				$20,300,898.00
	Total Distribution Revenue				$23,219,130.21
R-02 Limited Traffic Signal	Customer Charge		7,368	$0.00	$0.00
	Distribution kWh Charge		4,450,000	$0.00867	$38,581.50
	Total Distribution Revenue				$38,581.50
E-40 Storage Cooling	Customer Charge		185	$75.15	$13,902.75
	Distribution Peak kWh Charge	34.29%	2,633,472	$0.02536	$66,784.85
	Distribution Off-Peak kWh Charge	65.71%	5,046,528	$0.00949	$47,891.55
	Total Distribution kWh Charge		7,680,000		$114,676.40
	Total Distribution Revenue				$128,579.15
V-02 Business Space Heating	Customer Charge		2,498	$7.85	$19,609.30
	Distribution kWh Charge		6,170,000	$0.03038	$187,444.60
	Total Distribution Revenue				$207,053.90
G-02 General C&I	Customer Charge		82,592	$103.41	$8,540,838.72
	Distribution kW Charge(in excess of 10 kW)		3,059,655.7	$2.91	$8,903,598.21
	Distribution kWh Charge		1,113,000,000	$0.00992	$11,040,960.00
	HVD Credit		47,150	($0.37)	($17,445.46)
	HVM Credit (1)		-0.017%		($4,924.62)
	Total Distribution kWh Charge				$11,018,589.92
	Total Distribution Revenue				$28,463,026.85
	(1) Based on Test Year Data				

Column (3): per Company forecast
Column (4) per current tariffs; kWh charges include Settlement credit of $0.00038 per kWh
Column (5): Column (3) times Column (4)

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The Narragansett Electric Company
Rate Year Normalized Revenues

Rate Class/Description (1)	Description of Charges (2)	Units (3)	Rate (4)	Revenues (5)
G-22 Limited Medium C&I	Customer Charge	29,827	$0.00	$0.00
	Distribution kW Charge	1,194,814.5	$1.50	$1,792,221.82
	Distribution kWh Charge	361,170,000	$0.02215	$7,999,915.50
	Power Factor Credits			($8,378.64)
	Total Distribution kWh Charge			$7,991,536.86
	Total Distribution			$9,783,758.68
G-32 200 kW Demand	Customer Charge	12,160	$236.43	$2,874,988.80
	Distribution kW Charge	5,851,129.7	$1.56	$9,127,762.27
	Second Feeder Service Revenues	32,000	$2.41	$77,120.00
	Distribution kWh Charge	2,138,610,000	$0.01101	$23,546,096.10
	HVD Credit - Pri (1)	1,565,368	($0.37)	($579,186.09)
	HVD Credit - 115kV (1)	126,602	($2.41)	($305,109.86)
	HVM Credit (1)	-0.360%		(127,976)
	Total Distribution kWh Charges			$22,610,944.31
	Total Distribution Revenue			$34,613,695.38
	(1) Based on Test Year Data			
G-62 ^00 kW Demand	Customer Charge	132	$17,118.72	$2,259,671.04
	Distribution kW Charge	651,131.2	$0.75	$488,348.38
	Distribution kWh Charge	315,690,000	$0.00396	$1,250,132.40
	HVD Credit - Pri (1)	545,041	($0.37)	($201,664.99)
	HVD Credit - 115kV			
	HVM Credit (1)	-1.161%		(46,419)
	Total Distribution kWh Charge			$1,002,048.87
	Total Distribution Revenue			$3,750,068.29
	(1) Based on Test Year Data			
N-01 69 kV Rate	Customer Charge	12	$17,118.72	$205,424.64
	Distribution kW Charge	223,129.0	$0.75	$167,346.76
	Distribution kWh Charge	119,720,000	$0.00396	$474,091.20
	HVD	223,129	($0.37)	($82,557.74)
	HVM - Dist	$846,862.60	-1%	($8,468.63)
	HVM - Transition	1,130,157	-1%	($11,301.57)
	Total Distribution kWh Charge			$371,763.27
	Total Distribution Revenue			$744,534.67

Column (3): per Company forecast
Column (4) per current tariffs: kWh charges include Settlement credit of $0.00038 per kWh
Column (5): Column (3) times Column (4)

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The Narragansett Electric Company
Rate Year Normalized Revenues

Rate Class/Description (1)	Description of Charges (2)		Units (3)	Rate (4)	Revenues (5)
B-62 3000 kW Demand - Backup	Customer Charge		24	$17,118.72	$410,849.28
	Backup Distribution kW Charge		151,884.0	$0.75	$113,913.00
	Supplemental Distribution kW Charge		225,989.8	$0.75	$169,492.37
		Total	377,873.8		
	Backup Distribution kWh Charge		41,148,327	$0.00396	$162,947.38
	Supplemental Distribution kWh Charge		177,401,673	$0.00396	$702,510.62
		Total	218,550,000		
	HVD Credit (1)		104,643.0	($0.37)	($38,717.91)
	HVM Credit (1)		-2.03%		($31,699.60)
	Total Demand Charges				$283,405.37
	Total Energy Charges				$795,040.49
	Total Distribution Revenue				$1,489,295.14
	(1) Based on Test Year Data				
X-01 Electric Propulsion	Customer Charge		12	$10,000.00	$120,000.00
	Distribution kWh Charge		26,230,000	$0.00396	$103,870.80
	Total Distribution				$223,870.80
M-1 Station Power	Distribution Charge		36	$3,500.00	$126,000.00
	Distribution kWh Charges		798,000	$0.00	$0.00

Column (3): per Company forecast
Column (4) per current tariffs; kWh charges include Settlement credit of $0.00038 per kWh
Column (5): Column (3) times Column (4)

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The Narragansett Electric Company
Rate Year Normalized Revenues

s-10

Fixture Type -1	Lumens -2	-3	Pole Description -4	Lumen Code -5	Pole Code -6	Unit Price -7	Pole Charge -8	Units at YE December -9	Unit Rev -10	Pole Rev -11	Total Customer Charges -12	Annual kWh/unit -13	Total Ann kWhs -14
Section 1. Development of Customer Charge Revenue													
MERCURY VAPOR	8,000 (Post Top)	UG	Fibergl no base	2	R	$108.85	$57.34		$0.00	$0.00	$0.00	908	-
MERCURY VAPOR	4,000	OH	Wood	3	P	$58.40	$55.45	23	$1,343.20	$1,275.35	$2,618.55	561	12,903
MERCURY VAPOR	4,000	UG	Fibergl no base	3	R	$58.40	$57.34		$0.00	$0.00	$0.00	561	-
MERCURY VAPOR	4,000	UG	Metal w/foundation	3	T	$58.40	$253.37		$0.00	$0.00	$0.00	561	-
MERCURY VAPOR	4,000			3	XS	$58.40	$0.00	165	$9,636.00	$0.00	$9,636.00	561	92,565
MERCURY VAPOR	4,000			3	C	$58.40	$111.04	7	$408.80	$777.28	$1,186.08	561	3,927
MERCURY VAPOR	8,000	OH	Wood	4	P	$70.77	$55.45	-	$0.00	$0.00	$0.00	908	-
MERCURY VAPOR	8,000	UG	Fibergl no base	4	R	$70.77	$57.34	120	$8,492.40	$6,880.80	$15,373.20	908	108,960
MERCURY VAPOR	8,000	UG	Metal w/foundation	4	T	$70.77	$253.37	16	$1,132.32	$4,053.92	$5,186.24	908	14,528
MERCURY VAPOR	8,000			4	XS	$70.77	$0.00	135	$9,553.95	$0.00	$9,553.95	908	122,580
MERCURY VAPOR	22,000	OH	Wood	5	P	$122.31	$55.45	27	$3,302.37	$1,497.15	$4,799.52	1,897	51,219
MERCURY VAPOR	22,000	UG	Metal w/foundation	5	T	$122.31	$253.37	8	$978.48	$2,026.96	$3,005.44	1,897	15,176
MERCURY VAPOR	22,000			5	XS	$122.31	$0.00	72	$8,806.32	$0.00	$8,806.32	1,897	136,584
MERCURY VAPOR	63,000	UG	Metal w/foundation	6	T	$234.25	$253.37		$0.00	$0.00	$0.00	4,569	-
MERCURY VAPOR	63,000			6	XS	$234.25	$0.00	6	$1,405.50	$0.00	$1,405.50	4,569	27,414
INCANDESCENT	1,000			10	XS	$75.22	$0.00	14	$1,053.08	$0.00	$1,053.08	440	6,160
INCANDESCENT	2,500			11	XS	$67.45	$0.00		$0.00	$0.00	$0.00	845	-
MERCURY VAPOR	8,000			16	XS	$70.77	$0.00		$0.00	$0.00	$0.00	908	-
MERCURY VAPOR	15,000 (Providence)	UG	Metal w/foundation	17	T	$122.97	$253.37		$0.00	$0.00	$0.00	1,874	-
MERCURY VAPOR	15,000 (Providence)			17	XS	$122.97	$0.00		$0.00	$0.00	$0.00	1,874	-
MERCURY VAPOR	15,000 (Outside)			18	XS	$122.97	$0.00		$0.00	$0.00	$0.00	1,874	-
Flood lights	22,000	OH	Wood	23	P	$152.08	$55.45	21	$3,193.68	$1,164.45	$4,358.13	1,897	39,837
Flood lights	22,000	UG	Fibergl no base	23	R	$152.08	$57.34		$0.00	$0.00	$0.00	1,897	-
Flood lights	22,000	UG	Metal w/foundation	23	T	$152.08	$253.37	3	$456.24	$760.11	$1,216.35	1,897	5,691
Flood lights	22,000			23	XS	$152.08	$0.00	842	$128,051.36	$0.00	$128,051.36	1,897	1,597,274
Flood lights	63,000	OH	Wood	24	P	$262.72	$55.45	6	$1,576.32	$332.70	$1,909.02	4,569	27,414
Flood lights	63,000			24	XS	$262.72	$0.00	461	$121,113.92	$0.00	$121,113.92	4,569	2,106,309
INCANDESCENT	1,000			50	XS	$75.22	$0.00		$0.00	$0.00	$0.00	440	-
MERCURY VAPOR	22,000 - 24 HR			64	XS	$222.87	$0.00		$0.00	$0.00	$0.00	3,794	-
SODIUM VAPOR	4,000	OH	Wood	70	P	$62.78	$55.45	-	$0.00	$0.00	$0.00	248	-
SODIUM VAPOR	4,000	UG	Fibergl no base	70	R	$62.78	$57.34		$0.00	$0.00	$0.00	248	-
SODIUM VAPOR	4,000	UG	Metal w/foundation	70	T	$62.78	$253.37		$0.00	$0.00	$0.00	248	-
SODIUM VAPOR	4,000			70	XS	$62.78	$0.00	64	$4,017.92	$0.00	$4,017.92	248	15,872
SODIUM VAPOR	4,000	UG	Fibergl base<25 ft	70	C	$62.78	$111.04		$0.00	$0.00	$0.00	248	-
SODIUM VAPOR	4,000	UG	Fibergl base>=25 ft	70	D	$62.78	$185.67		$0.00	$0.00	$0.00	248	-
SODIUM VAPOR	5,800	OH	Wood	71	P	$66.28	$55.45	24	$1,590.72	$1,330.80	$2,921.52	349	8,376
SODIUM VAPOR	5,800	UG	Fibergl no base	71	R	$66.28	$57.34	9	$596.52	$516.06	$1,112.58	349	3,141
SODIUM VAPOR	5,800	UG	Metal w/foundation	71	T	$66.28	$253.37		$0.00	$0.00	$0.00	349	-
SODIUM VAPOR	5,800			71	XS	$66.28	$0.00	287	$19,022.36	$0.00	$19,022.36	349	100,163
SODIUM VAPOR	9,600	OH	Wood	72	P	$72.63	$55.45	1	$72.63	$55.45	$128.08	490	490
SODIUM VAPOR	9,600	UG	Fibergl no base	72	R	$72.63	$57.34		$0.00	$0.00	$0.00	490	-
SODIUM VAPOR	9,600	UG	Metal w/foundation	72	T	$72.63	$253.37	10	$726.30	$2,533.70	$3,260.00	490	4,900
SODIUM VAPOR	9,600			72	XS	$72.63	$0.00	141	$10,240.83	$0.00	$10,240.83	490	69,090
SODIUM VAPOR	9,600	UG	Fibergl base<25 ft	72	C	$72.63	$111.04		$0.00	$0.00	$0.00	490	-
SODIUM VAPOR	9,600	UG	Fibergl base>=25 ft	72	D	$72.63	$185.67		$0.00	$0.00	$0.00	490	-
SODIUM VAPOR	9,600			73	XS	$72.63	$0.00	10	$726.30	$0.00	$726.30	490	4,900
SODIUM VAPOR	27,500	OH	Wood	74	P	$120.39	$55.45	14	$1,685.46	$776.30	$2,461.76	1,284	17,976
SODIUM VAPOR	27,500	UG	Fiberglass base	74	R	$120.39	$57.34		$0.00	$0.00	$0.00	1,284	-
SODIUM VAPOR	27,500	UG	Metal w/foundation	74	T	$120.39	$253.37		$0.00	$0.00	$0.00	1,284	-
SODIUM VAPOR	27,500			74	XS	$120.39	$0.00	152	$18,299.28	$0.00	$18,299.28	1,284	195,168
SODIUM VAPOR	50,000	OH	Wood	75	P	$163.46	$55.45	2	$326.92	$110.90	$437.82	1,968	3,936
SODIUM VAPOR	50,000	UG	Metal w/foundation	75	T	$163.46	$253.37	11	$1,798.06	$2,787.07	$4,585.13	1,968	21,648
SODIUM VAPOR	50,000			75	XS	$163.46	$0.00	40	$6,538.40	$0.00	$6,538.40	1,968	78,720
DIUM VAPOR	27,500 (Flood)	OH	Wood	77	P	$143.14	$55.45	32	$4,580.48	$1,774.40	$6,354.88	1,284	41,088
IUM VAPOR	27,500 (Flood)	UG	Metal w/foundation	77	T	$143.14	$253.37	7	$1,001.98	$1,773.59	$2,775.57	1,284	8,988
IUM VAPOR	27,500 (Flood)			77	XS	$143.14	$0.00	1,251	$179,068.14	$0.00	$179,068.14	1,284	1,606,284
DIUM VAPOR	50,000 (Flood)	OH	Wood	78	P	$181.37	$55.45	102	$18,499.74	$5,655.90	$24,155.64	1,968	200,736
SODIUM VAPOR	50,000 (Flood)	UG	Metal w/foundation	78	T	$181.37	$253.37	9	$1,632.33	$2,280.33	$3,912.66	1,968	17,712
SODIUM VAPOR	50,000 (Flood)			78	XS	$181.37	$0.00	2,288	$414,974.56	$0.00	$414,974.56	1,968	4,502,784
SODIUM VAPOR	9,600 (Post top)	UG	Fibergl no base	79	R	$78.56	$57.34	8	$628.48	$458.72	$1,087.20	490	3,920
SODIUM VAPOR	9,600 (Post top)			79	XS	$78.56	$0.00		$0.00	$0.00	$0.00	490	-
SODIUM VAPOR	9,600 (Post top)	UG	Fibergl base<25 ft	79	C	$78.56	$111.04		$0.00	$0.00	$0.00	490	-
(Metal Halide)				80	XS	$181.37	$0.00	43	$7,798.91	$0.00	$7,798.91	1,968	84,624
(5800 URD Fiberglass)				83	XS	$66.28	$0.00	60	$3,976.80	$0.00	$3,976.80	349	20,940
SODIUM VAPOR	27,500(24 HR)	UG	Metal w/foundation	84	T	$172.21	$253.37		$0.00	$0.00	$0.00	2,568	-
SODIUM VAPOR	27,500(24 HR)			84	XS	$172.21	$0.00		$0.00	$0.00	$0.00	2,568	-
MERCURY VAPOR	63,000	UG	Metal w/foundation	090	T	$36.31	$253.37		$0.00	$0.00	$0.00	4,569	-
MERCURY VAPOR	15,000	UG	Metal w/foundation	091	T	$103.43	$253.37		$0.00	$0.00	$0.00	3,748	-
MERCURY VAPOR	22,000	UG	Metal w/foundation	092	T	$102.11	$253.37		$0.00	$0.00	$0.00	3,794	-
MERCURY VAPOR	22,000			092	XS	$355.48	$0.00		$0.00	$0.00	$0.00	3,794	-
SODIUM VAPOR	27,500	UG	Metal w/foundation	093	T	$98.27	$253.37		$0.00	$0.00	$0.00	2,568	-
MERCURY VAPOR	22,000	UG	Metal w/foundation	095	T	$102.11	$253.37		$0.00	$0.00	$0.00	3,794	-
MERCURY VAPOR	63,000	UG	Metal w/foundation	096	T	$325.99	$253.37		$0.00	$0.00	$0.00	9,138	-
SODIUM VAPOR	27,500	UG	Metal w/foundation	097	T	$98.27	$253.37		$0.00	$0.00	$0.00	2,568	-
SODIUM VAPOR	50,000	UG	Metal w/foundation	098	T	$62.78	$253.37		$0.00	$0.00	$0.00	3,936	-
SODIUM VAPOR (INC.CONV)	4,000			710	XS	$62.78	$0.00		$0.00	$0.00	$0.00	248	-
SODIUM VAPOR (INC.CONV)	4,000	UG	Metal w/foundation	711	T	$62.78	$253.37		$0.00	$0.00	$0.00	248	-
SODIUM VAPOR (INC.CONV)	4,000			711	XS	$62.78	$0.00		$0.00	$0.00	$0.00	248	-
SODIUM VAPOR (INC.CONV)	4,000			750	XS	$62.78	$0.00		$0.00	$0.00	$0.00	248	-
SODIUM VAPOR (INC.CONV)	4,000			755	XS	$62.78	$0.00		$0.00	$0.00	$0.00	248	-
SODIUM VAPOR (INC.CONV	4,000			756	XS	$62.78	$0.00		$0.00	$0.00	$0.00	248	-
Total								6,491	$998,307.06	$38,821.94	$1,037,129.00		11,379,997

Column Descriptions:
(1)-(8) Fixture and Pole description and prices per current tariff
(9) Fixture inventory at year ending December 2003
(10) Column (7) x Column (9)
(11) Column (8) x Column (9)
(12) Column (10) + Column (11)
(13) per tariff
(14) Column (9) x Column (13)

Section 2. Development of kWh Charges

Rate Year Annual kWhs 11,379,997 from Section 1., Column (14) total

	Annual kWh Use (a)	% Use by former EUA/NEES Company (b)	Estimated Proforma Use by former Company (c)	Base Charge (d)	Base Rev (e)	Credit (f)	Credit to Base Rev (g)	Total Dist Rev (h)
Annual kWh Usage - Narragansett	4,990,641	43.53%	4,954,071	$0.00396	$19,618		$0	$19,618
Annual kWh Usage - Blackstone	4,619,079	40.30%	4,585,783	$0.00396	$18,160	($0.04420)	($202,692)	($184,532)
Annual kWh Usage - Newport	1,852,904	16.17%	1,840,143	$0.00396	$7,287	($0.02918)	($53,695)	($46,408)
Distribution Energy Charge Rev	11,462,624		11,379,997		$45,065		($256,387)	($211,322)

Column Descriptions
(a) Test year kWhs usage from SMB702 monthly revenue reports
(b) Column (a) / total Column (a)
(c) Column (b) x Proforma Annual kWhs
(d) per tariff
(e) Column (c) x Column (d)
tariff
nn (c) x Column (f)
nn (e) + Column (g)

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The Narragansett Electric Company
Rate Year Normalized Revenues

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Fixture Type (1)	Lumens (2)	(3)	Pole Description (4)	Lumen Code (5)	Pole Code (6)	Unit Price (7)	Pole Charge (8)	Units at YE December (9)	Unit Rev (10)	Pole Rev (11)	Total Customer Charges (12)	Annual kWh/unit (13)	Total Ann kWHs (14)
Section 1. Development of Customer Charge Revenue													
MERCURY VAPOR	8,000 (Post Top)	UG	Fibergl no base	2	R	$108.85	$110.86	2	$217.70	$221.72	$439.42	908	1,816
MERCURY VAPOR	4,000	OH	Wood	3	P	$58.40	$110.86	0	$0.00	$0.00	$0.00	561	-
MERCURY VAPOR	4,000	UG	Fibergl no base	3	R	$58.40	$110.86	31	$1,810.40	$3,436.66	$5,247.06	561	17,391
MERCURY VAPOR	4,000	UG	Metal w/foundation	3	T	$58.40	$110.86	9	$525.60	$997.74	$1,523.34	561	5,049
MERCURY VAPOR	4,000			3	XS	$58.40	$0.00	2537	$148,160.80	$0.00	$148,160.80	561	1,423,257
MERCURY VAPOR	8,000	OH	Wood	4	P	$70.77	$110.86	0	$0.00	$0.00	$0.00	908	-
MERCURY VAPOR	8,000	UG	Fibergl no base	4	R	$70.77	$110.86	10	$707.70	$1,108.60	$1,816.30	908	9,080
MERCURY VAPOR	8,000	UG	Metal w/foundation	4	T	$70.77	$110.86	79	$5,590.83	$8,757.94	$14,348.77	908	71,732
MERCURY VAPOR	8,000			4	XS	$70.77	$0.00	757	$53,572.89	$0.00	$53,572.89	908	687,356
MERCURY VAPOR	22,000	OH	Wood	5	P	$122.31	$110.86	1	$122.31	$110.86	$233.17	1,897	1,897
MERCURY VAPOR	22,000	UG	Metal w/foundation	5	T	$122.31	$110.86	657	$80,357.67	$72,835.02	$153,192.69	1,897	1,246,329
MERCURY VAPOR	22,000			5	XS	$122.31	$0.00	518	$63,356.58	$0.00	$63,356.58	1,897	982,646
MERCURY VAPOR	63,000	UG	Metal w/foundation	6	T	$234.25	$110.86	45	$10,541.25	$4,988.70	$15,529.95	4,569	205,605
MERCURY VAPOR	63,000			6	XS	$234.25	$0.00	40	$9,370.00	$0.00	$9,370.00	4,569	182,760
INCANDESCENT	1,000			10	XS	$75.22	$0.00	62	$4,663.64	$0.00	$4,663.64	440	27,280
INCANDESCENT	2,500			11	XS	$67.45	$0.00	3	$202.35	$0.00	$202.35	845	2,535
MERCURY VAPOR	8,000			16	XS	$70.77	$0.00		$0.00	$0.00	$0.00	908	-
MERCURY VAPOR	15,000 (Providence)	UG	Metal w/foundation	17	T	$122.97	$110.86	82	$10,083.54	$9,090.52	$19,174.06	1,874	153,668
MERCURY VAPOR	15,000 (Providence)			17	XS	$122.97	$0.00	11	$1,352.67	$0.00	$1,352.67	1,874	20,614
MERCURY VAPOR	15,000 (Outside)			18	XS	$122.97	$0.00	58	$7,132.26	$0.00	$7,132.26	1,874	108,692
Flood lights	22,000	OH	Wood	23	P	$152.08	$110.86		$0.00	$0.00	$0.00	1,897	-
Flood lights	22,000	UG	Fibergl no base	23	R	$152.08	$110.86		$0.00	$0.00	$0.00	1,897	-
Flood lights	22,000	UG	Metal w/foundation	23	T	$152.08	$110.86		$0.00	$0.00	$0.00	1,897	-
Flood lights	22,000			23	XS	$152.08	$0.00		$0.00	$0.00	$0.00	1,897	-
Flood lights	63,000	OH	Wood	24	P	$262.72	$110.86		$0.00	$0.00	$0.00	4,569	-
Flood lights	63,000			24	XS	$262.72	$0.00		$0.00	$0.00	$0.00	4,569	-
INCANDESCENT	1,000			50	XS	$75.22	$0.00		$0.00	$0.00	$0.00	440	-
MERCURY VAPOR	22,000 - 24 HR			64	XS	$222.87	$0.00		$0.00	$0.00	$0.00	3,794	-
SODIUM VAPOR	4,000	OH	Wood	70	P	$62.78	$110.86	6	$376.68	$665.16	$1,041.84	248	1,488
SODIUM VAPOR	4,000	UG	Fibergl no base	70	R	$62.78	$110.86	74	$4,645.72	$8,203.64	$12,849.36	248	18,352
SODIUM VAPOR	4,000	UG	Metal w/foundation	70	T	$62.78	$110.86	20	$1,255.60	$2,217.20	$3,472.80	248	4,960
SODIUM VAPOR	4,000			70	XS	$62.78	$0.00	19473	$1,222,514.94	$0.00	$1,222,514.94	248	4,829,304
SODIUM VAPOR	4,000	UG	Fibergl base<25 ft	70	C	$62.78	$110.86		$0.00	$0.00	$0.00	248	-
SODIUM VAPOR	4,000	UG	Fibergl base>=25 ft	70	D	$62.78	$110.86		$0.00	$0.00	$0.00	248	-
SODIUM VAPOR	5,800	OH	Wood	71	P	$66.28	$110.86	0	$0.00	$0.00	$0.00	349	-
SODIUM VAPOR	5,800	UG	Fibergl no base	71	R	$66.28	$110.86	5	$331.40	$554.30	$885.70	349	1,745
SODIUM VAPOR	5,800	UG	Metal w/foundation	71	T	$66.28	$110.86	0	$0.00	$0.00	$0.00	349	-
SODIUM VAPOR	5,800			71	XS	$66.28	$0.00	335	$22,203.80	$0.00	$22,203.80	349	116,915
SODIUM VAPOR	9,600	OH	Wood	72	P	$72.63	$110.86	32	$2,324.16	$3,547.52	$5,871.68	490	15,680
SODIUM VAPOR	9,600	UG	Fibergl no base	72	R	$72.63	$110.86	116	$8,425.08	$12,859.76	$21,284.84	490	56,840
SODIUM VAPOR	9,600	UG	Metal w/foundation	72	T	$72.63	$110.86	150	$10,894.50	$16,629.00	$27,523.50	490	73,500
SODIUM VAPOR	9,600			72	XS	$72.63	$0.00	10150	$737,194.50	$0.00	$737,194.50	490	4,973,500
SODIUM VAPOR	9,600	UG	Fibergl base<25 ft	72	C	$72.63	$110.86		$0.00	$0.00	$0.00	490	-
SODIUM VAPOR	9,600	UG	Fibergl base>=25 ft	72	D	$72.63	$110.86		$0.00	$0.00	$0.00	490	-
SODIUM VAPOR	9,600			73	XS	$72.63	$0.00		$0.00	$0.00	$0.00	490	-
SODIUM VAPOR	27,500	OH	Wood	74	P	$120.39	$110.86	0	$0.00	$0.00	$0.00	1,284	-
SODIUM VAPOR	27,500	UG	Fibergl no base	74	R	$120.39	$110.86	0	$0.00	$0.00	$0.00	1,284	-
SODIUM VAPOR	27,500	UG	Metal w/foundation	74	T	$120.39	$110.86	1658	$199,606.62	$183,805.88	$383,412.50	1,284	2,128,872
SODIUM VAPOR	27,500			74	XS	$120.39	$0.00	11140	$1,341,144.60	$0.00	$1,341,144.60	1,284	14,303,760
SODIUM VAPOR	50,000	OH	Wood	75	P	$163.46	$110.86	0	$0.00	$0.00	$0.00	1,968	-
SODIUM VAPOR	50,000	UG	Metal w/foundation	75	T	$163.46	$110.86	203	$33,182.38	$22,504.58	$55,686.96	1,968	399,504
SODIUM VAPOR	50,000			75	XS	$163.46	$0.00	806	$131,748.76	$0.00	$131,748.76	1,968	1,586,208
SODIUM VAPOR	27,500 (Flood)	OH	Wood	77	P	$143.14	$110.86		$0.00	$0.00	$0.00	1,284	-
SODIUM VAPOR	27,500 (Flood)	UG	Metal w/foundation	77	T	$143.14	$110.86		$0.00	$0.00	$0.00	1,284	-
SODIUM VAPOR	27,500 (Flood)			77	XS	$143.14	$0.00		$0.00	$0.00	$0.00	1,284	-
SODIUM VAPOR	50,000 (Flood)	OH	Wood	78	P	$181.37	$110.86	0	$0.00	$0.00	$0.00	1,968	-
SODIUM VAPOR	50,000 (Flood)	UG	Metal w/foundation	78	T	$181.37	$110.86	0	$0.00	$0.00	$0.00	1,968	-
SODIUM VAPOR	50,000 (Flood)			78	XS	$181.37	$0.00	288	$52,234.56	$0.00	$52,234.56	1,968	566,784
SODIUM VAPOR	9,600 (Post top)	UG	Fibergl no base	79	R	$78.56	$110.86		$0.00	$0.00	$0.00	490	-
SODIUM VAPOR	9,600 (Post top)			79	XS	$78.56	$0.00		$0.00	$0.00	$0.00	490	-
SODIUM VAPOR	9,600 (Post top)	UG	Fibergl base<25 ft	79	C	$78.56	$110.86		$0.00	$0.00	$0.00	490	-
(Metal Halide)				80	XS	$181.37	$0.00		$0.00	$0.00	$0.00	490	-
(5800 URD Fiberglass)				83	XS	$66.28	$0.00		$0.00	$0.00	$0.00	490	-
SODIUM VAPOR	27,500(24 HR)	UG	Metal w/foundation	84	T	$172.21	$110.86	1	$172.21	$110.86	$283.07	2,568	2,568
SODIUM VAPOR	27,500(24 HR)			84	XS	$172.21	$0.00	41	$7,060.61	$0.00	$7,060.61	2,568	105,288
MERCURY VAPOR	63,000	UG	Metal w/foundation	090	T	$178.82	$110.86	2	$357.64	$221.72	$579.36	4,569	9,138
MERCURY VAPOR	15,000	UG	Metal w/foundation	091	T	$245.94	$110.86	7	$1,721.58	$776.02	$2,497.60	3,748	26,236
MERCURY VAPOR	22,000	UG	Metal w/foundation	092	T	$244.62	$110.86	5	$1,223.10	$554.30	$1,777.40	3,794	18,970
SODIUM VAPOR	27,500	UG	Metal w/foundation	093	T	$240.78	$110.86	5	$1,203.90	$554.30	$1,758.20	2,568	12,840
SODIUM VAPOR	27,500			093	XS	$351.64	$0.00	6	$2,109.84	$0.00	$2,109.84	2,568	15,408
MERCURY VAPOR	22,000	UG	Metal w/foundation	095	T	$244.62	$110.86	35	$8,561.70	$3,880.10	$12,441.80	3,794	132,790
MERCURY VAPOR	63,000	UG	Metal w/foundation	096	T	$468.50	$110.86	1	$468.50	$110.86	$579.36	9,138	9,138
SODIUM VAPOR	27,500	UG	Metal w/foundation	097	T	$240.78	$110.86	10	$2,407.80	$1,108.60	$3,516.40	2,568	25,680
SODIUM VAPOR	50,000	UG	Metal w/foundation	098	T	$62.78	$110.86	12	$753.36	$1,330.32	$2,083.68	3,936	47,232
SODIUM VAPOR (INC.CONV)	4,000			710	XS	$62.78	$0.00	10634	$667,602.52	$0.00	$667,602.52	248	2,637,232
SODIUM VAPOR (INC.CONV)	4,000			711	XS	$62.78	$0.00	611	$38,358.58	$0.00	$38,358.58	248	151,528
SODIUM VAPOR (INC.CONV)	4,000	UG	Metal w/foundation	750	T	$62.78	$110.86	1	$62.78	$110.86	$173.64	248	248
SODIUM VAPOR (INC.CONV)	4,000			750	XS	$62.78	$0.00	491	$30,824.98	$0.00	$30,824.98	248	121,768
SODIUM VAPOR (INC.CONV)	4,000			755	XS	$62.78	$0.00	2403	$150,860.34	$0.00	$150,860.34	248	595,944
SODIUM VAPOR (INC.CONV)	4,000			756	XS	$62.78	$0.00	456	$28,627.68	$0.00	$28,627.68	248	113,088
	Total							64079	$5,108,228.61	$361,292.74	$5,469,521.35		38,250,215

Column Descriptions:
(1)-(8) Change in December fixture inventory from June inventory
(9) Fixture inventory at year ending December 2003
(10) Column (7) x Column (9)
(11) Column (8) x Column (9)
(12) Column (10) + Column (11)
(13) per tariff
(14) Column (9) x Column (13)

Section 2. Development of kWh Charges

Rate Year Annual kWhs 38,250,215 from Section 1., Column (14) total

	Proforma Forecasted kWhs	Base Charge	Base Rev	Credit	Credit to Base Rev	Total Dist Rev
	(a)	(b)	(c)	(d)	(e)	(f)
Annual kWh Usage - Narragansett	38,250,215	$0.00396	$151,470.85	$0.00	$0.00	$151,470.85

Column Descriptions
(a) from Section 1, Column (14) total
(b) per tariff
(c) Column (a) x Column (b)
(d) per tariff
(e) Column (c) x Column (d)
(f) Column (c) + Column (e)

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The Narragansett Electric Company
Rate Year Normalized Revenues

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Fixture Type -1	Lumens -2	-3	Pole Description -4	Lumen Code -5	Pole Code -6	Unit Price -7	Pole Charge -8	Units at YE December -9	Unit Rev -10	Pole Rev -11	Total Customer Charges -12	Annual kWh/unit -13	Total Ann kWhs -14
Section 1. Development of Customer Charge Revenue													
MERCURY VAPOR	8,000 (Post Top)	UG	Fibergl no base	2	R	$108.85	$57.34	2	$217.70	$114.68	$332.38	908	1,816
MERCURY VAPOR	4,000	OH	Wood	3	P	$58.40	$55.45	94	$5,489.60	$5,212.30	$10,701.90	561	52,734
MERCURY VAPOR	4,000	UG	Fibergl no base	3	R	$58.40	$57.34	16	$934.40	$917.44	$1,851.84	561	8,976
MERCURY VAPOR	4,000	UG	Metal w/foundation	3	T	$58.40	$253.37	70	$4,088.00	$17,735.90	$21,823.90	561	39,270
MERCURY VAPOR	4,000			3	XS	$58.40	$0.00	2128	$124,275.20	$0.00	$124,275.20	561	1,193,808
MERCURY VAPOR	4,000			3	C	$58.40	$111.04	4	$233.60	$444.16	$677.76	561	2,244
MERCURY VAPOR	8,000	OH	Wood	4	P	$70.77	$55.45	1	$70.77	$55.45	$126.22	908	908
MERCURY VAPOR	8,000	UG	Fibergl no base	4	R	$70.77	$57.34	0	$0.00	$0.00	$0.00	908	-
MERCURY VAPOR	8,000	UG	Metal w/foundation	4	T	$70.77	$253.37	5	$353.85	$1,266.85	$1,620.70	908	4,540
MERCURY VAPOR	8,000			4	XS	$70.77	$0.00	62	$4,387.74	$0.00	$4,387.74	908	56,296
MERCURY VAPOR	22,000	OH	Wood	5	P	$122.31	$55.45	6	$733.86	$332.70	$1,066.56	1,897	11,382
MERCURY VAPOR	22,000	UG	Metal w foundation	5	T	$122.31	$253.37	269	$32,901.39	$68,156.53	$101,057.92	1,897	510,293
MERCURY VAPOR	22,000			5	XS	$122.31	$0.00	341	$41,707.71	$0.00	$41,707.71	1,897	646,877
MERCURY VAPOR	22,000			5	C	$122.31	$111.04	5	$611.55	$555.20	$1,166.75	1,897	9,485
MERCURY VAPOR	63,000	UG	Metal w foundation	6	T	$234.25	$253.37		$0.00	$0.00	$0.00	4,569	-
MERCURY VAPOR	63,000			6	XS	$234.25	$0.00		$0.00	$0.00	$0.00	4,569	-
INCANDESCENT	1,000			10	P	$75.22	$55.45	3	$225.66	$166.35	$392.01	440	1,320
INCANDESCENT	1,000			10	XS	$75.22	$0.00	262	$19,707.64	$0.00	$19,707.64	440	115,280
INCANDESCENT	2,500			11	XS	$67.45	$0.00	29	$1,956.05	$0.00	$1,956.05	845	24,505
MERCURY VAPOR	8,000			16	XS	$70.77	$0.00	1	$70.77	$0.00	$70.77	908	908
MERCURY VAPOR	15,000 (Providence)	UG	Metal w/foundation	17	T	$122.97	$253.37		$0.00	$0.00	$0.00	1,874	-
MERCURY VAPOR	15,000 (Providence)			17		$122.97	$0.00	0	$0.00	$0.00	$0.00	1,874	-
MERCURY VAPOR	15,000 (Outside)			18		$122.97	$0.00	0	$0.00	$0.00	$0.00	1,874	-
Flood lights	22,000	OH	Wood	23	P	$152.08	$55.45	4	$608.32	$221.80	$830.12	1,897	7,588
Flood lights	22,000	UG	Fibergl no base	23	R	$152.08	$57.34	6	$912.48	$344.04	$1,256.52	1,897	11,382
Flood lights	22,000	UG	Metal w foundation	23	T	$152.08	$253.37	0	$0.00	$0.00	$0.00	1,897	-
Flood lights	22,000			23	XS	$152.08	$0.00	30	$4,562.40	$0.00	$4,562.40	1,897	56,910
Flood lights	63,000	OH	Wood	24	P	$262.72	$55.45	0	$0.00	$0.00	$0.00	4,569	-
Flood lights	63,000			24	XS	$262.72	$0.00	8	$2,101.76	$0.00	$2,101.76	4,569	36,552
INCANDESCENT	1,000			50	XS	$75.22	$0.00		$0.00	$0.00	$0.00	440	-
MERCURY VAPOR	22,000 - 24 HR			64	XS	$222.87	$0.00	0	$0.00	$0.00	$0.00	1,794	-
SODIUM VAPOR	4,000	OH	Wood	70	P	$62.78	$55.45	39	$2,448.42	$2,162.55	$4,610.97	248	9,672
SODIUM VAPOR	4,000	UG	Fibergl no base	70	R	$62.78	$57.34	88	$5,524.64	$5,045.92	$10,570.56	248	21,824
SODIUM VAPOR	4,000	UG	Metal w/foundation	70	T	$62.78	$253.37	26	$1,632.28	$6,587.62	$8,219.90	248	6,448
SODIUM VAPOR	4,000			70	XS	$62.78	$0.00	7750	$486,545.00	$0.00	$486,545.00	248	1,922,000
SODIUM VAPOR	4,000	UG	Fibergl base<25 ft	70	C	$62.78	$111.04	10	$627.80	$1,110.40	$1,738.20	248	2,480
SODIUM VAPOR	4,000	UG	Fibergl base > 25 ft	70	D	$62.78	$185.67	39	$2,448.42	$7,241.13	$9,689.55	248	9,672
SODIUM VAPOR	5,800	OH	Wood	71	P	$66.28	$55.45	25	$1,657.00	$1,386.25	$3,043.25	349	8,725
SODIUM VAPOR	5,800	UG	Fibergl no base	71	R	$66.28	$57.34	168	$11,135.04	$9,633.12	$0.00	349	58,632
SODIUM VAPOR	5,800	UG	Metal w/foundation	71	T	$66.28	$253.37	80	$5,302.40	$20,269.60	$0.00	349	27,920
SODIUM VAPOR	5,800			71	XS	$66.28	$0.00	13730	$910,024.40	$0.00	$910,024.40	349	4,791,770
SODIUM VAPOR	9,600	OH	Wood	72	P	$72.63	$55.45	2	$145.26	$110.90	$256.16	490	980
SODIUM VAPOR	9,600	UG	Fibergl no base	72	R	$72.63	$57.34	185	$13,436.55	$10,607.90	$24,044.45	490	90,650
SODIUM VAPOR	9,600	UG	Metal w/foundation	72	T	$72.63	$253.37	211	$15,324.93	$53,461.07	$68,786.00	490	103,390
SODIUM VAPOR	9,600			72	XS	$72.63	$0.00	4283	$311,074.29	$0.00	$311,074.29	490	2,098,670
SODIUM VAPOR	9,600	UG	Fibergl base<25 ft	72	C	$72.63	$111.04	11	$798.93	$1,221.44	$2,020.37	490	5,390
SODIUM VAPOR	9,600	UG	Fibergl base > 25 ft	72	D	$72.63	$185.67	3	$217.89	$557.01	$774.90	490	1,470
SODIUM VAPOR	9,600			73	XS	$72.63	$0.00	22	$1,597.86	$0.00	$1,597.86	490	10,780
SODIUM VAPOR	27,500	OH	Wood	74	P	$120.39	$55.45	9	$1,083.51	$499.05	$1,582.56	1,284	11,556
SODIUM VAPOR	27,500	UG	Fibergl no base	74	R	$120.39	$57.34	1	$120.39	$57.34	$177.73	1,284	1,284
SODIUM VAPOR	27,500	UG	Metal w foundation	74	T	$120.39	$253.37	531	$63,927.09	$134,539.47	$198,466.56	1,284	681,804
SODIUM VAPOR	27,500			74	XS	$120.39	$0.00	3562	$428,829.18	$0.00	$428,829.18	1,284	4,573,608
SODIUM VAPOR	50,000	OH	Wood	75	P	$163.46	$55.45	1	$163.46	$55.45	$218.91	1,968	1,968
SODIUM VAPOR	50,000	UG	Metal w foundation	75	T	$163.46	$253.37	30	$4,903.80	$7,601.10	$12,504.90	1,968	59,040
SODIUM VAPOR	50,000			75	XS	$163.46	$0.00	286	$46,749.56	$0.00	$46,749.56	1,968	562,848
SODIUM VAPOR	27,500 (Flood)	OH	Wood	77	P	$143.14	$55.45	8	$1,145.12	$443.60	$1,588.72	1,284	10,272
SODIUM VAPOR	27,500 (Flood)	UG	Metal w/foundation	77	T	$143.14	$253.37	13	$1,860.82	$3,293.81	$5,154.63	1,284	16,692
SODIUM VAPOR	27,500 (Flood)			77	XS	$143.14	$0.00	288	$41,224.32	$0.00	$41,224.32	1,284	369,792
SODIUM VAPOR	50,000 (Flood)	OH	Wood	78	P	$181.37	$55.45	23	$4,171.51	$1,275.35	$5,446.86	1,968	45,264
SODIUM VAPOR	50,000 (Flood)	UG	Metal w/foundation	78	T	$181.37	$253.37	7	$1,269.59	$1,773.59	$3,043.18	1,968	13,776
SODIUM VAPOR	50,000 (Flood)			78	XS	$181.37	$0.00	564	$102,292.68	$0.00	$102,292.68	1,968	1,109,952
SODIUM VAPOR	9,600 (Post top)	UG	Fibergl no base	79	R	$78.56	$57.34	394	$30,952.64	$22,591.96	$53,544.60	490	193,060
SODIUM VAPOR	9,600 (Post top)			79	XS	$78.56	$0.00	32	$2,513.92	$0.00	$2,513.92	490	15,680
SODIUM VAPOR	9,600 (Post top)	UG	Fibergl base<25 ft	79	C	$78.56	$111.04	86	$6,756.16	$9,549.44	$16,305.60	490	42,140
(Metal Halide)				80	XS	$181.37	$0.00	4	$725.48	$0.00	$725.48	1,968	7,872
(5800 URD Fiberglass)				81	XS	$66.28	$0.00	196	$12,990.88	$0.00	$12,990.88	349	68,404
SODIUM VAPOR	27,500(24 HR)	UG	Metal w/foundation	84	T	$172.21	$253.37		$0.00	$0.00	$0.00	2,568	-
SODIUM VAPOR	27,500(24 HR)			84		$172.21	$0.00		$0.00	$0.00	$0.00	2,568	-
MERCURY VAPOR	63,000	UG	Metal w foundation	090			$0.00		$0.00	$0.00	$0.00	4,569	-
MERCURY VAPOR	15,000	UG	Metal w/foundation	091			$0.00		$0.00	$0.00	$0.00	3,748	-
MERCURY VAPOR	22,000	UG	Metal w/foundation	092			$0.00		$0.00	$0.00	$0.00	3,794	-
MERCURY VAPOR	22,000			092	XS				$0.00	$0.00	$0.00	3,794	-
SODIUM VAPOR	27,500	UG	Metal w/foundation	093			$0.00		$0.00	$0.00	$0.00	2,568	-
MERCURY VAPOR	22,000	UG	Metal w/foundation	095			$0.00		$0.00	$0.00	$0.00	3,794	-
MERCURY VAPOR	63,000	UG	Metal w/foundation	096			$0.00		$0.00	$0.00	$0.00	9,138	-
SODIUM VAPOR	27,500	UG	Metal w/foundation	097			$0.00		$0.00	$0.00	$0.00	2,568	-
SODIUM VAPOR	50,000	UG	Metal w foundation	098		$62.78	$0.00		$0.00	$0.00	$0.00	3,936	-
SODIUM VAPOR (INC.CONV)	4,000			710					$0.00	$0.00	$0.00	248	-
SODIUM VAPOR (INC.CONV)	4,000	UG	Metal w/foundation	711	T	$62.78	$253.37		$0.00	$0.00	$0.00	248	-
SODIUM VAPOR (INC.CONV)	4,000			711	XS				$0.00	$0.00	$0.00	248	-
SODIUM VAPOR (INC.CONV)	4,000			750	XS	$62.78	$0.00		$0.00	$0.00	$0.00	248	-
SODIUM VAPOR (INC.CONV)	4,000			755	XS	$62.78	$0.00		$0.00	$0.00	$0.00	248	-
SODIUM VAPOR (INC.CONV	4,000			756	XS	$62.78	$0.00		$0.00	$0.00	$0.00	248	-
Total								36053	$2,767,771.67	$396,598.47	$3,118,029.98		19,748,559

Column Descriptions
(1)-(8) Annual kWhs per fixture
(9) Fixture inventory at year ending December 2003
(10) Column (7) x Column (9)
(11) Column (8) x Column (9)
(12) Column (10) + Column (11)
(13) per tariff
(14) Column (9) x Column (13)

Section 2. Development of kWh Charges

Proforma Annual kWhs 19,748,559 from Section 1, Column (14) total

	Annual kWh Use (a)	% Use by former EUA NEES Company (b)	Estimated Proforma Use by former Company (c)	Base Charge (d)	Base Rev (e)	Credit (f)	Credit to Base Rev (g)	Total Dist Rev (h)
Annual kWh Usage - Narragansett	[illegible]	34.28%	6,770,271	$0.00396	$26,810		$0	$26,810
Annual kWh Usage - Blackstone	[illegible]	48.12%	9,503,515	$0.00396	$37,634	($0.04420)	($420,055)	($382,421)
Annual kWh Usage - Newport	[illegible]	17.60%	3,474,772	$0.00396	$13,760	($0.02918)	($101,393)	($87,634)
Proforma Distribution Energy Charge Rev	19,723,647		19,748,559		$78,204		($521,449)	($443,245)

Column Descriptions
(a) Test year kWhs usage from SMB702 monthly revenue reports
(b) Column (a) / total Column (a)
(c) Column (b) x Proforma Annual kWhs
(d) per tariff
(e) Column (c) x Column (d)
(f) per tariff
(g) Column (c) x Column (f)
(h) Column (e) + Column (g)

Commission Data Request 1-94

Request:

Regarding Narragansett's sister companies in Massachusetts & New Hampshire, please provide a brief summary of the following by company:

(a) Type of regulation (traditional cost of service, PBR,.)
(b) Authorized rates of return on equity
(c) Brief summary of any earnings sharing plans
(d) Brief summary of any merger savings plans

Response:

(a) Massachusetts: Massachusetts Electric Company ("Mass. Electric") has been operating under a distribution rate freeze in effect since May 2000. The distribution rate freeze extends through February 2005, at which time, under Mass. Electric's rate plan settlement, the company may increase its distribution rates $10 million, subject to the company's average distribution rate remaining at or below 90% of the regional average distribution rate for unbundled distribution companies in the Northeast. The company may adjust its rates through the Rate Index Period (through 2009) by the annual change in such regional average rate, subject to the 90% regional average cap.
New Hampshire: Granite State Electric Company ("Granite State") operates under traditional cost of service regulation for distribution rates.

(b) Massachusetts: Mass. Electric's most recent authorized return on equity ("ROE") for distribution rates is 11.0%, which was established in Docket DPU/DTE 96-25.
New Hampshire: Granite State's most recent authorized return on equity ("ROE") for distribution rates is 10.0%, which was established in Docket No. DE 95-169 (1996).

(c) Massachusetts: Mass. Electric does not have an earnings sharing mechanism in its rate plan.
New Hampshire: Granite State has no earnings sharing plan.

(d) Massachusetts: Mass. Electric has a merger savings mechanism in its rate plan. Under the company's rate plan settlement, Mass. Electric is authorized to include for recovery earned savings in its cost of service for setting distribution rates beginning January 1, 2010. Such earned savings amount is to be determined based on the difference between normalized distribution revenue generated from distribution rates in effect during 2009, subject to certain exclusions for service quality rate adjustments and exogenous factor rate adjustments, and a pro forma cost of service which would exclude any acquisition premium amortization and/or transaction costs associated with the NEES/EUA and NEES/National Grid mergers. The difference is then to be adjusted to an after tax difference based upon the federal and state income tax rate in effect at the time. The sharing formula in the rate plan settlement provides that the company's earned savings shall be the lesser of (1) 100% of the after tax

difference up to $43 million, plus 50 percent of the after tax difference in excess of $43 million, or (2) $66 million. Once the company's earned shavings amount is determined, it is then to be grossed up for federal and state income taxes for the purpose of inclusion in the cost of service. Such earned savings shall be included in future cost of service studies for the setting of distribution rates through 2019.
New Hampshire: Granite State has not been part of any operating company mergers, therefore has no merger savings plan.

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

Commission Data Request 1-95

Request:

What is the authorized rate of return on equity for each electric distribution company in New England? Please attach each order from each state commission.

Response:

Please see the Attachment to this response, which provides a summary of the information requested. Due to the voluminous nature of the requested regulatory orders, these materials are provided in separately on compact diskette only.

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

	Utility	Jurisdiction	Allowed Return on Equity	Docket Order No. Date	Page	Pdf File Name
(1)	Connecticut Light & Power	Connecticut	9.85%	Docket No. 03-07-02 Issued: 12/17/2003	145	CLP030702
(2)	The United Illuminating Company	Connecticut	10.45%	Docket No. 01-10-10 Issued: 09/26/2002	27	UIL01-10-10
(3)	Central Maine Power	Maine	10.50%	Docket 97-580 Issued: 03/19/1999	62	CMP97-580
(4)	Fitchburg Gas and Electric Light Company	Massachusetts	10.00%	Docket DTE 02-24/25 Issued: 12/02/2002	Sch.#3	FG02-24
(5)	Boston Edison	Massachusetts	11.75%	Docket DPU 92-92 Issued: 10/30/1992	10	BECO92-92
(6)	Commonwealth Electric	Massachusetts	12.00%	Docket DPU 90-331 Issued: 07/01/1991	225	ComElec90-331
(7)	Cambridge Electric	Massachusetts	11.00%	Docket DPU 92-250 Issued: 05/28/1993	162	CELCo92-250
(8)	Massachusetts Electric	Massachusetts	11.00%	Docket DPU 96-25 Issued: 02/26/1997		MECO96-25
(9)	Western Massachusetts Electric Company	Massachusetts	11.00%	Docket DTE 97-120 Issued: 09/17/1999	61	WMEC97-120
(10)	Unitil Service Corp.	New Hampshire	9.67%	Docket DE 01-247 Order No. 24,072 Issued: 10/25/2002	24	Unitil01-247
(11)	Granite State Electric	New Hampshire	10.00%	Docket DR 95-169 Order No. 22,141 Issued: 05/13/1996	9	GSEDR95-169
(12)	Public Service Company of New Hampshire	New Hampshire	11.00%	Docket DE 99-099 Order No. 23,549 Issued: 09/08/2000		PSCNH99-099
(13)	Central Vermont Public Service	Vermont	11.00%	Docket No.6460 Issued: 06/26/2001	68	CVPS6460
(14)	Green Mountain Power Corp.	Vermont	10.50%	Docket No.6867 Issued: 12/22/2003	5	GMP6867

Commission Data Request 1-96

Request:

Indicate what rates of return on equity have been adopted by public utilities commissions since January 1, 2003, for each electric distribution company in the country.

Response:

According to reports complied by Regulatory Research Associates, Inc. ("RRA"), the average electric equity return authorized by state commissions since January 1, 2003 was 10.88%, based on 30 observations. During the first half of 2004, RRA reports the average electric equity return authorized by state commissions to be 10.63%, based on 8 observations. A copy of the RRA reports dated January 22, 2004, "Major Rate Case Decisions—January 2002-December 2003, Supplemental Study," and July 8, 2004, "Major Rate Case Decisions—January-June 2004," which include equity return details in electric utility decisions from January 1, 2003 through June 30, 2004, are attached to this response

Prepared by or under the supervision of: Robert H. McLaren

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Regulatory Research Associates, Inc. REGULATORY FOCUS RRA

30 MONTGOMERY STREET JERSEY CITY, NEW JERSEY 07302 (201) 433-5507

Regulatory Study
January 22, 2004

MAJOR RATE CASE DECISIONS--JANUARY 2002-DECEMBER 2003 SUPPLEMENTAL STUDY

In conjunction with the preparation of the Regulatory Study entitled *Major Rate Case Decisions--January 1990-December 2003*, which will be distributed in the next few weeks, RRA has prepared a chronological listing of all cases in that study for the years 2002 and 2003, by type of utility service. These listings, with key data concerning each case, appear on pages 7 through 12 of this Supplemental Study. Tables summarizing cases decided in the last 11 years appear on pages 2 and 3, and graphs summarizing the authorized equity returns in the last 13 years appear on pages 4 through 6. The average equity return authorized electric utilities in 2003 approximated 11%, down slightly from 11.2% in 2002. There were 22 electric equity return determinations in both 2003 and 2002. The average return on equity (ROE) authorized gas utilities approximated 11% in both 2003 and 2002. There were 25 gas cases that included an ROE determination in 2003 and 21 in 2002. For the telecommunications industry, there were no ROE determinations in 2003 and 2002.

Over the last several years there have been fewer equity return determinations relative to the 1980's and early 1990's. The reasons for this phenomenon include: industry restructuring/intensifying competition; more efficient utility operations; technological improvements; relatively low inflation and interest rates; accelerated depreciation/amortization programs; the increased utilization of settlements that do not specify return parameters; and, the growing use of performance or price-based regulation. As the number of equity return determinations declined, the average authorized ROE has less of a relationship to the return that the typical electric, gas, or telecommunications company has an opportunity to earn from regulated operations. In addition, electric industry restructuring in many states has led to the unbundling of rates, with commissions authorizing revenue requirement and return parameters for distribution operations only, thus further complicating data comparability. Over the last two years, we have seen a modest rise in the number of equity return determinations, largely the result of increased employee insurance and pension expenses, and environmental compliance costs.

The individual electric and gas cases listed on pages 7 through 12 are presented with the decision date shown first, followed by the company name, the abbreviation of the state issuing the decision, the authorized rate of return (ROR) and ROE, and the common equity component in the adopted capital structure. If the capital structure contained cost-free capital or investment tax credit balances at the overall rate of return, an asterisk (*) follows the number in this column. Next we show the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base, and the amount of the permanent rate change authorized. For telecommunications cases, the decision date is listed first, followed by the company name, the state abbreviation, and the amount of the permanent rate change authorized. The dollar amount represents the permanent rate change ordered at the time a decision was issued. In a few cases an interim rate change was previously ordered. Fuel adjustment clause rate changes are not reflected in this study.

(Text continued on page 6)

Average Equity Returns Authorized January 1993 - December 2003

(Return Percent - No. of Observations)

	Period	Electric Utilities	Gas Utilities	Telephone Utilities
1993	Full Year	11.41 (32)	11.35 (45)	11.83 (12)
1994	Full Year	11.34 (31)	11.35 (28)	11.81 (11)
1995	Full Year	11.55 (33)	11.43 (16)	12.08 (8)
1996	Full Year	11.39 (22)	11.19 (20)	11.74 (4)
1997	1st Quarter	11.30 (4)	11.31 (7)	11.80 (1)
	2nd Quarter	11.62 (3)	11.70 (1)	11.60 (1)
	3rd Quarter	12.00 (1)	12.00 (1)	11.70 (1)
	4th Quarter	11.11 (3)	10.99 (4)	11.35 (2)
1997	Full Year	11.40 (11)	11.29 (13)	11.56 (5)
1998	1st Quarter	11.31 (4)	— (0)	11.30 (1)
	2nd Quarter	12.20 (1)	11.37 (3)	— (0)
	3rd Quarter	11.80 (2)	11.41 (3)	— (0)
	4th Quarter	11.83 (3)	11.69 (4)	— (0)
1998	Full Year	11.66 (10)	11.51 (10)	11.30 (1)
1999	1st Quarter	10.58 (4)	10.82 (3)	13.00 (1)
	2nd Quarter	10.94 (4)	10.82 (3)	— (0)
	3rd Quarter	10.63 (8)	— (0)	— (0)
	4th Quarter	11.08 (4)	10.33 (3)	— (0)
1999	Full Year	10.77 (20)	10.66 (9)	13.00 (1)
2000	1st Quarter	11.06 (5)	10.71 (1)	11.50 (1)
	2nd Quarter	11.11 (2)	11.08 (4)	— (0)
	3rd Quarter	11.68 (2)	11.33 (5)	11.25 (1)
	4th Quarter	12.08 (3)	12.50 (2)	— (0)
2000	Full Year	11.43 (12)	11.39 (12)	11.38 (2)
2001	1st Quarter	11.38 (2)	11.16 (4)	— (0)
	2nd Quarter	10.88 (2)	10.75 (1)	— (0)
	3rd Quarter	10.78 (8)	— (0)	— (0)
	4th Quarter	11.50 (6)	10.65 (2)	— (0)
2001	Full Year	11.09 (18)	10.95 (7)	— (0)
2002	1st Quarter	10.87 (5)	10.67 (3)	— (0)
	2nd Quarter	11.41 (6)	11.64 (4)	— (0)
	3rd Quarter	11.06 (4)	11.50 (3)	— (0)
	4th Quarter	11.20 (7)	10.78 (11)	— (0)
2002	Full Year	11.16 (22)	11.03 (21)	— (0)
2003	1st Quarter	11.47 (7)	11.38 (5)	— (0)
	2nd Quarter	11.16 (4)	11.36 (4)	— (0)
	3rd Quarter	9.95 (5)	10.61 (5)	— (0)
	4th Quarter	11.09 (6)	10.84 (11)	— (0)
2003	Full Year	10.97 (22)	10.99 (25)	— (0)

Electric Utilities--Summary Table*

	Period	ROR %	ROE %	Eq. as % Cap. Struc.	Amt. $ Mil.
1993	Full Year	9.46 (30)	11.41 (32)	47.40 (30)	1,164.1 (42)
1994	Full Year	9.29 (30)	11.34 (31)	45.15 (30)	1,116.9 (40)
1995	Full Year	9.44 (30)	11.55 (33)	45.90 (30)	455.7 (43)
1996	Full Year	9.21 (20)	11.39 (22)	44.34 (20)	-5.6 (38)
1997	Full Year	9.16 (12)	11.40 (11)	48.79 (11)	-553.3 (33)
1998	Full Year	9.44 (9)	11.66 (10)	46.14 (8)	-429.3 (31)
1999	Full Year	8.81 (18)	10.77 (20)	45.08 (17)	-1,683.8 (30)
2000	Full Year	9.20 (12)	11.43 (12)	48.85 (12)	-291.4 (34)
2001	Full Year	8.93 (15)	11.09 (18)	47.20 (13)	14.2 (21)
2002	1st Quarter	8.51 (5)	10.87 (5)	46.15 (4)	-495.3 (5)
	2nd Quarter	9.05 (5)	11.41 (6)	44.35 (6)	61.0 (8)
	3rd Quarter	7.88 (3)	11.06 (4)	47.22 (3)	-81.0 (5)
	4th Quarter	9.01 (7)	11.20 (7)	47.80 (6)	39.9 (6)
2002	Full Year	8.72 (20)	11.16 (22)	46.27 (19)	-475.4 (24)
2003	1st Quarter	9.07 (6)	11.47 (7)	49.94 (5)	48.2 (7)
	2nd Quarter	9.07 (4)	11.16 (4)	49.46 (4)	116.2 (5)
	3rd Quarter	8.22 (5)	9.95 (5)	46.09 (5)	69.6 (5)
	4th Quarter	9.07 (5)	11.09 (6)	52.17 (5)	210.4 (5)
2003	Full Year	8.86 (20)	10.97 (22)	49.41 (19)	444.4 (22)

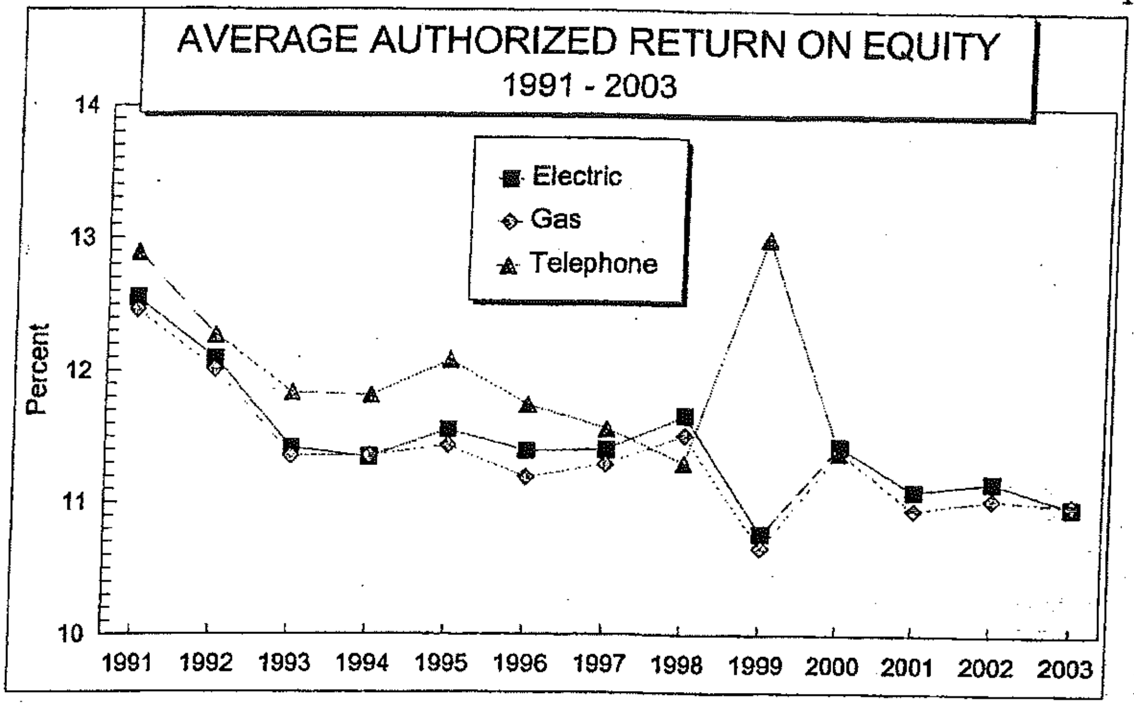
Gas Utilities--Summary Table*

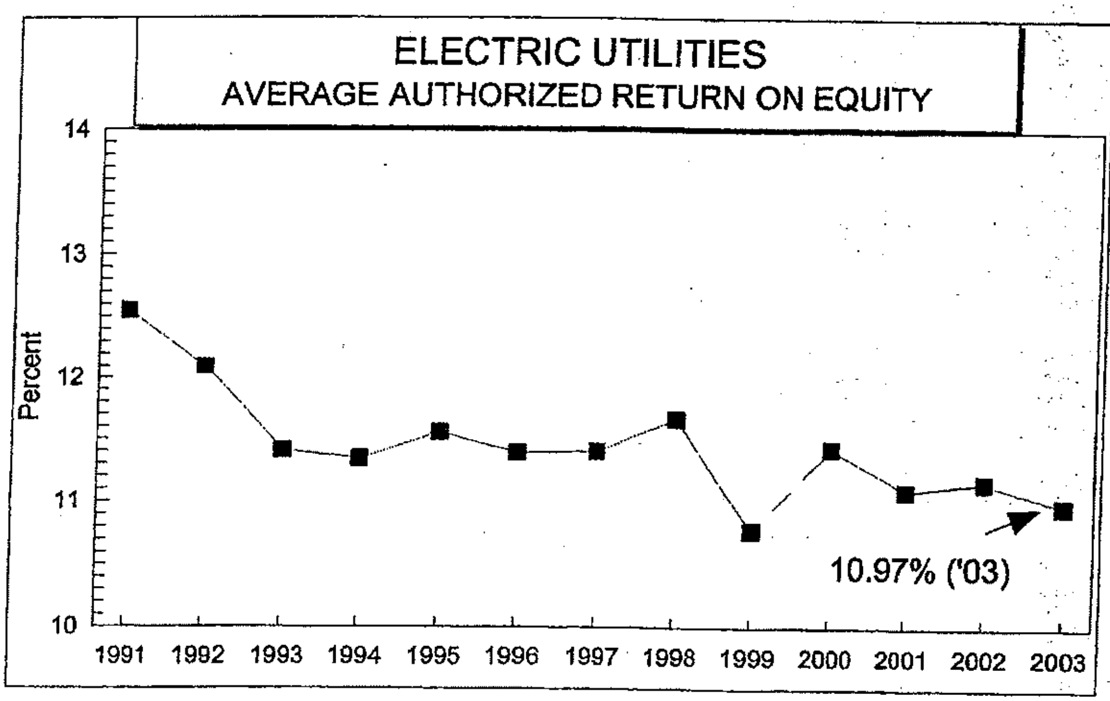
	Period	ROR %	ROE %	Eq. as % Cap. Struc.	Amt. $ Mil.
1993	Full Year	9.44 (41)	11.35 (45)	46.15 (41)	217.8 (49)
1994	Full Year	9.51 (32)	11.35 (28)	48.12 (27)	422.9 (42)
1995	Full Year	9.64 (16)	11.43 (16)	49.98 (15)	-61.5 (31)
1996	Full Year	9.25 (23)	11.19 (20)	47.69 (19)	193.4 (34)
1997	Full Year	9.13 (13)	11.29 (13)	47.78 (11)	-82.5 (21)
1998	Full Year	9.46 (10)	11.51 (10)	49.50 (10)	93.9 (20)
1999	Full Year	8.86 (9)	10.66 (9)	49.06 (9)	51.0 (14)
2000	Full Year	9.33 (13)	11.39 (12)	48.59 (12)	135.9 (20)
2001	Full Year	8.51 (6)	10.95 (7)	43.96 (5)	114.0 (11)
2002	1st Quarter	8.55 (3)	10.67 (3)	49.10 (2)	86.7 (5)
	2nd Quarter	9.38 (3)	11.64 (4)	49.67 (3)	-9.3 (4)
	3rd Quarter	8.66 (4)	11.50 (3)	45.43 (3)	102.3 (6)
	4th Quarter	8.76 (10)	10.78 (11)	48.58 (10)	123.9 (11)
2002	Full Year	8.80 (20)	11.03 (21)	48.29 (18)	303.6 (26)
2003	1st Quarter	8.97 (4)	11.38 (5)	50.69 (4)	35.9 (6)
	2nd Quarter	9.09 (3)	11.36 (4)	50.32 (3)	14.2 (5)
	3rd Quarter	8.54 (4)	10.61 (5)	45.74 (4)	89.5 (6)
	4th Quarter	8.64 (11)	10.84 (11)	51.06 (11)	120.5 (13)
2003	Full Year	8.75 (22)	10.99 (25)	49.93 (22)	260.1 (30)

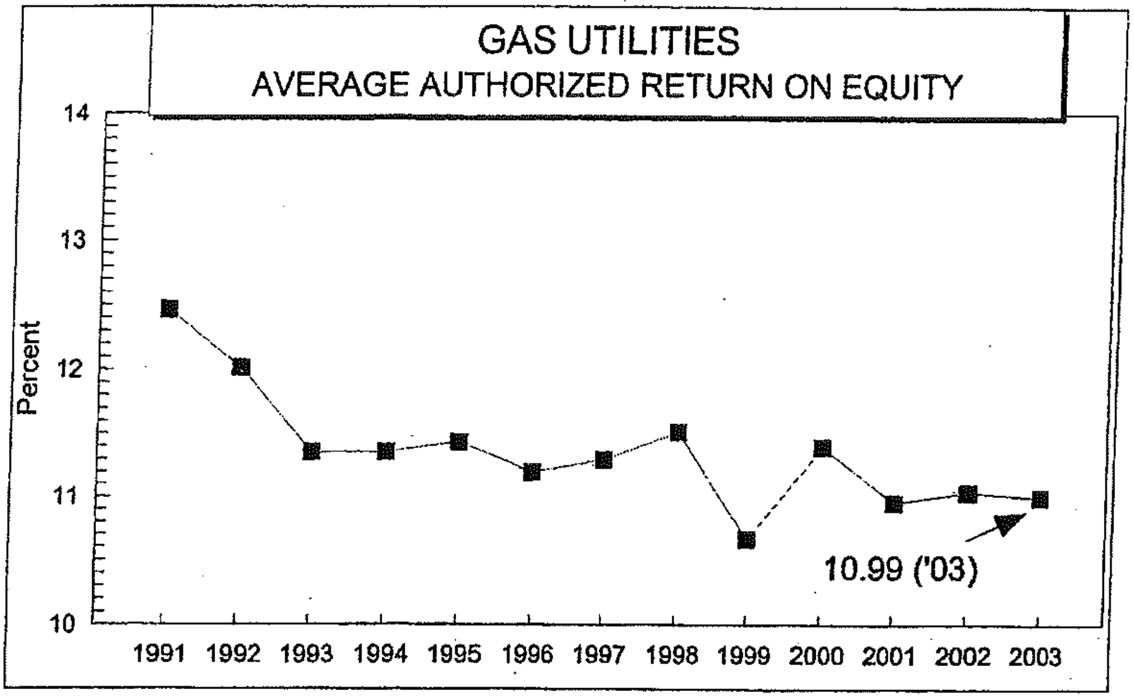
Telephone Utilities--Summary Table*

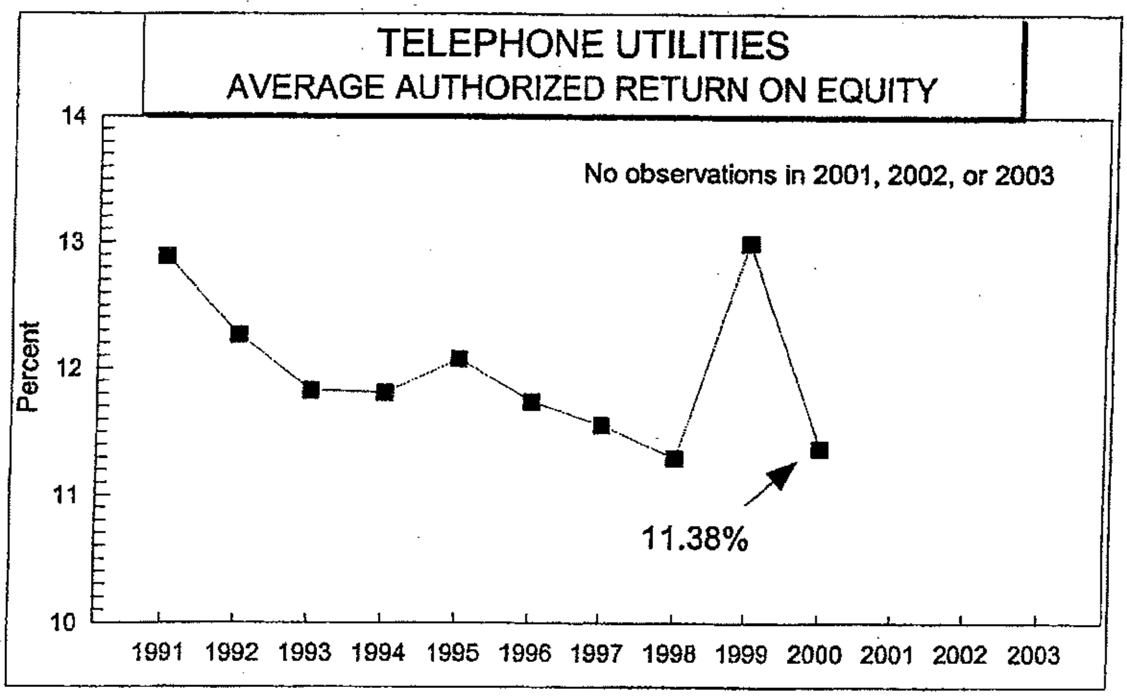
	Period	ROR %	ROE %	Eq. as % Cap. Struc.	Amt. $ Mil.
1993	Full Year	10.26 (12)	11.83 (12)	56.45 (12)	-198.1 (12)
1994	Full Year	9.91 (12)	11.81 (11)	57.46 (11)	-236.6 (16)
1995	Full Year	9.81 (8)	12.08 (8)	55.02 (7)	-264.0 (14)
1996	Full Year	9.65 (2)	11.74 (4)	56.00 (2)	-348.2 (11)
1997	Full Year	9.57 (5)	11.56 (5)	55.84 (5)	-154.4 (7)
1998	Full Year	9.37 (1)	11.30 (1)	52.00 (1)	-323.3 (13)
1999	Full Year	11.34 (1)	13.00 (1)	66.90 (1)	-570.1 (19)
2000	Full Year	9.52 (2)	11.38 (2)	56.59 (2)	-390.4 (14)
2001	Full Year	9.61 (1)	--- (0)	--- (0)	-130.0 (8)
2002	1st Quarter	--- (0)	--- (0)	--- (0)	1.8 (1)
	2nd Quarter	--- (0)	--- (0)	--- (0)	19.5 (2)
	3rd Quarter	--- (0)	--- (0)	--- (0)	-13.6 (1)
	4th Quarter	--- (0)	--- (0)	--- (0)	--- (0)
2002	Full Year	--- (0)	--- (0)	--- (0)	7.7 (4)
2003	1st Quarter	--- (0)	--- (0)	--- (0)	--- (0)
	2nd Quarter	--- (0)	--- (0)	--- (0)	-27.6 (1)
	3rd Quarter	--- (0)	--- (0)	--- (0)	-35.0 (1)
	4th Quarter	--- (0)	--- (0)	--- (0)	--- (0)
2003	Full Year	--- (0)	--- (0)	--- (0)	-62.6 (2)

* Number of observations each period indicated in parentheses.


AVERAGE AUTHORIZED RETURN ON EQUITY
1991 - 2003
Electric
Gas
Telephone
Percent
14
13
12
11
10
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003


ELECTRIC UTILITIES
AVERAGE AUTHORIZED RETURN ON EQUITY
Percent
14
13
12
11
10
10.97% ('03)
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003

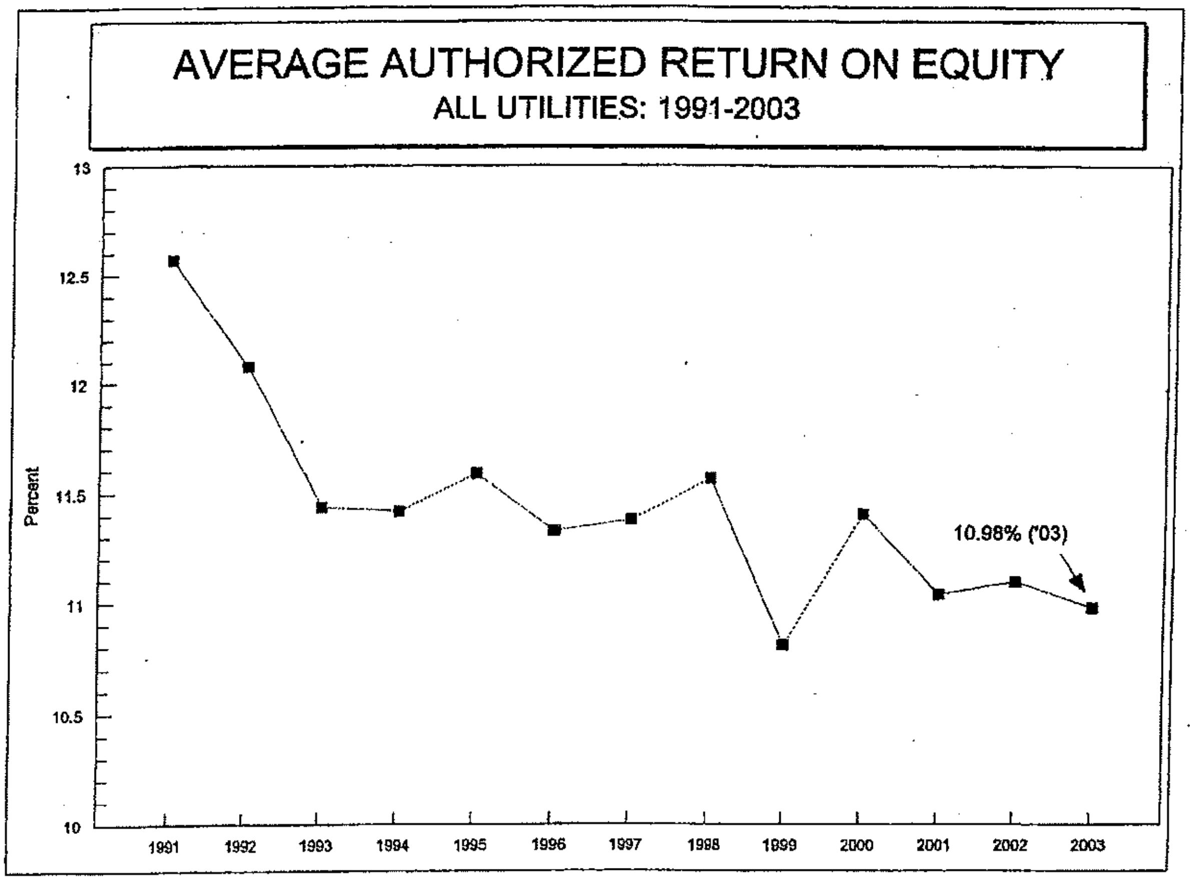

GAS UTILITIES
AVERAGE AUTHORIZED RETURN ON EQUITY
14
13
12
11
10
Percent
10.99 ('03)
1991 1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003


TELEPHONE UTILITIES
AVERAGE AUTHORIZED RETURN ON EQUITY
No observations in 2001, 2002, or 2003
14
13
12
11
10
Percent
11.38%
1991 1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003

The table on page 2 shows the average ROE, authorized annually since 1993 and by quarter since 1997, for the major electric, gas, and telecommunications rate decisions, followed by the number of observations in each period. The tables on page 3 show the composite electric, gas, and communications industry data for all the cases included in the chronology of this and earlier reports, summarized annually since 1993 and by quarter for the past eight quarters. The graphs on pages 4 and 5 show the average authorized equity returns for the three industry groups.

The graph below tracks the average equity return authorized for all electric, gas, and telecommunications rate cases combined, by year, for the last 12 years. As the graph reveals, since 1993 (with the exception of 1999) authorized ROEs have settled in the low to mid-11% range. The combined average equity returns authorized for all utilities for the years 1992 though 2003, on an annual basis, and the number of observations for each year are as follows:

1992	12.08%	(84)	1998	11.57%	(21)
1993	11.44	(89)	1999	10.81	(30)
1994	11.42	(70)	2000	11.41	(26)
1995	11.59	(57)	2001	11.05	(25)
1996	11.33	(46)	2002	11.10	(43)
1997	11.38	(29)	2003	10.98	(47)



ELECTRIC UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/22/02	Texas-New Mexico Power (NM)	7.35	10.00	—	12/00-YE	4.2 (B)
2/21/02	Missouri Public Service (MO)	—	—	—	—	-4.3 (B)
2/27/02	New York State Electric & Gas (NY)	—	—	—	—	-205.0 (B)
3/22/02	Florida Power & Light (FL)	—	—	—	—	-250.0 (B)
3/27/02	MidAmerican Energy (IL)	9.14	11.36	51.56	12/00-YE	— (1)
3/27/02	Nevada Power (NV)	8.37	10.10	42.59	5/01-YE	-40.2 (R)
3/28/02	Central Illinois Light (IL)	8.99	11.02	53.17	12/00-YE	— (1)
3/28/02	Illinois Power (IL)	8.69	11.89	37.27	12/00-YE	— (1)
2002	***1ST QUARTER AVERAGES/TOTAL***	**8.51**	**10.87**	**46.15**		**-495.3**
	OBSERVATIONS	**5**	**5**	**4**		**5**
4/23/02	Florida Power (FL)	—	—	—	—	-125.0 (B)
4/24/02	Montana-Dakota Utilities (ND)	10.24	11.80	48.87	12/01-A	-4.3
5/24/02	Kansas City Power & Light (KS)	—	—	—	—	-12.5 (B,E)
5/28/02	Sierra Pacific Power (NV)	8.61	10.17	39.19	7/01-YE	-13.7
6/10/02	Gulf Power (FL)	7.92	12.00 (2)	41.02 *	5/03-A	53.2
6/11/02	Bangor Hydro-Electric (ME)	—	—	—	—	— (3)
6/18/02	Avista Corp. (WA)	—	11.16	42.00	—	45.7 (B,I)
6/20/02	Puget Sound Energy (WA)	8.76	11.00	40.00 (Hy)	—	59.0 (B,I)
6/20/02	Wisconsin Public Service (WI)	9.71 (G)	12.30	54.99	12/02-A	58.6 (I)
2002	***2ND QUARTER AVERAGES/TOTAL***	**9.05**	**11.41**	**44.35**		**61.0**
	OBSERVATIONS	**5**	**6**	**6**		**8**
7/15/02	Citizens Communications (VT)	6.43	11.00 (4)	50.00	7/03-A	4.8
7/17/02	Entergy Louisiana (LA)	—	10.50	—	12/99 & 12/00	-5.0 (B)
7/25/02	Ameren UE (MO)	—	—	—	—	-110.0 (B,Z)
9/12/02	Wisconsin Power and Light (WI)	8.81 (G)	12.30	44.67	12/02-A	60.1 (I)
9/26/02	United Illuminating (CT)	8.41	10.45	47.00	12/00-A	-30.9
2002	***3RD QUARTER AVERAGES/TOTAL***	**7.88**	**11.06**	**47.22**		**-81.0**
	OBSERVATIONS	**3**	**4**	**3**		**5**
10/30/02	Portland General Electric (OR)	—	—	—	—	-1.2
11/7/02	Pacific Gas and Electric (CA)	9.24	11.22	48.00	12/03-A	—
11/7/02	San Diego Gas & Electric (CA)	8.77	10.90	49.00	12/03-A	—
11/7/02	Southern California Edison (CA)	9.75	11.60	48.00	12/03-A	—
11/14/02	Empire District Electric (MO)	—	—	—	—	11.0 (B)
12/3/02	Fitchburg Gas & Electric (MA)	8.50	10.00	40.82	12/01-YE	2.0
12/4/02	OGE Electric Service (OK)	9.12	11.55	56.00 (E)	9/01-YE	-25.0 (B)
12/13/02	Entergy Mississippi (MS)	9.09	11.75	44.99	12/03-A	48.2 (B)
12/20/02	Upper Peninsula Power (MI)	8.59	11.40	—	12/03	4.9 (B)
2002	***4TH QUARTER AVERAGES/TOTAL***	**9.01**	**11.20**	**47.80**		**39.9**
	OBSERVATIONS	**7**	**7**	**6**		**6**
2002	***FULL-YEAR AVERAGES/TOTAL***	**8.72**	**11.16**	**46.27**		**-475.4**
	OBSERVATIONS	**20**	**22**	**19**		**24**

ELECTRIC UTILITY DECISIONS (continued)

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
9/03	Entergy Gulf States (LA)	---	11.10	---	---	-22.1 (B)
28/03	Public Service Co. of New Mexico (NM)	---	---	---	---	-35.2 (B,Z,5)
1/31/03	South Carolina Electric & Gas (SC)	9.94	12.45	52.18	3/02-YE	70.7
2/28/03	Madison Gas and Electric (WI)	9.71 (G)	12.30	55.42	12/03-A	20.3
3/6/03	PacifiCorp (WY)	8.45	10.75	45.70	9/01-YE	8.7
3/7/03	Rochester Gas & Electric (NY)	8.11	9.96	41.40	6/03-A	-15.6 (6)
3/20/03	Wisconsin Public Service (WI)	9.24 (G)	12.00	55.00	12/03-A	21.4
3/28/03	Commonwealth Edison (IL)	8.99	11.72	---	12/02-YE	--- (I,B,7)
2003	***1ST QUARTER AVERAGES/TOTAL OBSERVATIONS***	**9.07** 6	**11.47** 7	**49.94** 5		**48.2** 7
4/3/03	Wisconsin Power & Light (WI)	9.04 (G)	12.00	51.72	12/03-A	77.1
4/15/03	Interstate Power & Light (IA)	9.08	11.15	47.20 (U)	12/01-A	25.8 (I,R)
5/15/03	Entergy New Orleans (LA)	---	---	---	---	18.4 (B)
6/25/03	Aquila (CO)	9.07	10.75	47.50	6/02-A	16.0 (B)
6/26/03	Public Service of Colorado (CO)	9.08	10.75	51.40	12/01-A	-21.1 (B)
2003	***2ND QUARTER AVERAGES/TOTAL OBSERVATIONS***	**9.07** 4	**11.16** 4	**49.46** 4		**116.2** 5
7/9/03	Public Service Electric & Gas (NJ)	8.18	9.75	41.45	12/02-YE	129.1 (B,8)
7/16/03	Rockland Electric (NJ)	8.02	9.75	46.00	4/03-YE	-7.2 (8)
7/25/03	Jersey Central Power & Light (NJ)	8.39	9.50	46.00	12/02-YE	-61.7 (8)
..6/03	PacifiCorp (OR)	8.28	10.50	46.00	3/04-A	8.5 (B)
9/3/03	Maine Public Service (ME)	8.25	10.25	51.00	12/02-A	0.9 (B,8)
2003	***3RD QUARTER AVERAGES/TOTAL OBSERVATIONS***	**8.22** 5	**9.95** 5	**46.09** 5		**69.6** 5
12/17/03	Connecticut Light & Power (CT)	8.19	9.85	47.22	12/02-YE	70.5 (Z,9)
12/17/03	PacifiCorp (UT)	8.43	10.70	47.04	3/03-A	65.0 (B)
12/18/03	Montana-Dakota Utilities (ND)	10.02	11.50	50.32	12/03-A	1.0 (B)
12/19/03	Wisconsin Power & Light (WI)	9.50 (G)	12.00	60.27	12/04-A	14.5
12/19/03	Wisconsin Public Service (WI)	9.20 (G)	12.00	56.00	12/04-A	59.4
12/22/03	Green Mountain Power (VT)	---	10.50	---	---	--- (B,10)
2003	***4TH QUARTER AVERAGES/TOTAL OBSERVATIONS***	**9.07** 5	**11.09** 6	**52.17** 5		**210.4** 5
2003	***FULL-YEAR AVERAGES/TOTAL OBSERVATIONS***	8.86 20	10.97 22	49.41 19		444.4 22

GAS UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/9/02	Public Service Electric & Gas (NJ)	8.27	10.00	—	6/01-YE	90.0 (B)
1/30/02	Yankee Gas Services (CT)	8.91	11.00	45.46	9/00-A	-4.0
1/31/02	Union Light, Heat & Power (KY)	8.48 (G)	11.00	52.73	9/00-YE	2.7
2/22/02	Connecticut Natural Gas (CT)	—	—	—	—	-0.5 (E,B)
2/22/02	Southern Connecticut Gas (CT)	—	—	—	—	-1.5 (E,B)
2002	***1ST QUARTER AVERAGES/TOTAL***	**8.55**	**10.67**	**49.10**		**86.7**
	OBSERVATIONS	**3**	**3**	**2**		**5**
4/17/02	Consolidated Edison of New York (NY)	—	11.50	—	9/04-A	-25.0 (B)
4/29/02	Atlanta Gas Light (GA)	9.16	11.00	47.00	4/03-A	-10.0 (B)
6/11/02	Cincinnati Gas & Electric (OH)	9.27	11.77 (E)	47.01	12/01(11)	15.1 (B)
6/20/02	Wisconsin Public Service (WI)	9.71 (G)	12.30	54.99	12/02-A	10.6 (I)
2002	***2ND QUARTER AVERAGES/TOTAL***	**9.38**	**11.64**	**49.67**		**-9.3**
	OBSERVATIONS	**3**	**4**	**3**		**4**
8/9/02	Centerpoint Energy Arkla (AR)	8.20	—	—	—	31.8 (B)
8/28/02	Puget Sound Energy (WA)	8.76	11.00	40.00 (Hy)	—	35.6 (B)
9/11/02	MidAmerican Energy (IL)	8.85	11.20	51.61	12/00-YE	(12)
9/12/02	Wisconsin Power and Light (WI)	8.81 (G)	12.30	44.67	12/02-A	21.5 (I)
9/23/02	North Carolina Natural Gas (NC)	—	—	—	—	4.1 (B)
9/27/02	Washington Gas of Maryland (MD)	—	—	—	12/01-YE	9.3 (B)
2002	***3RD QUARTER AVERAGES/TOTAL***	**8.66**	**11.50**	**45.43**		**102.3**
	OBSERVATIONS	**4**	**3**	**3**		**6**
10/3/02	Laclede Gas (MO)	—	—	—	—	14.0 (B)
10/28/02	Piedmont Natural Gas (NC)	9.44	11.30	52.66	11/01-YE	13.9 (B)
10/30/02	Washington Gas (DC)	8.83	10.60	54.00	12/00-YE	-5.4 (R)
11/7/02	Consumers Energy (MI)	7.45	11.40	34.59 *	12/02-A	55.7 (I)
11/7/02	Pacific Gas and Electric (CA)	9.24	11.22	48.00	12/03-A	—
11/7/02	San Diego Gas & Electric (CA)	8.77	10.90	49.00	12/03-A	—
11/8/02	MidAmerican Energy (IA)	9.10	10.75	53.32	12/01-A	17.7 (B,I)
11/20/02	Elizabethtown Gas (NJ)	7.95	10.00	52.50	5/02-YE	14.2 (B)
11/20/02	New York State Electric & Gas (NY)	—	10.50	—	9/03-A	0.0 (B,Z)
12/3/02	Fitchburg Gas & Electric (MA)	8.50	10.00	40.82	12/01-YE	3.0
12/4/02	Centerpoint Energy Arkla (OK)	8.69	10.75	48.30 (E)	12/01-A	7.4 (B)
12/13/02	Columbia Gas of Kentucky (KY)	—	—	—	—	-7.8 (B)
12/30/02	Questar Gas (UT)	9.64	11.20	52.61	12/02-YE	11.2
2002	***4TH QUARTER AVERAGES/TOTAL***	**8.76**	**10.78**	**48.58**		**123.9**
	OBSERVATIONS	**10**	**11**	**10**		**11**
2002	***FULL-YEAR AVERAGES/TOTAL***	**8.80**	**11.03**	**48.29**		**303.6**
	OBSERVATIONS	**20**	**21**	**18**		**26**

GAS UTILITY DECISIONS (continued)

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
'6/03	Peoples Gas System (FL)	8.83	11.25	50.92 *	12/03-A	12.1 (I,B)
2/18/03	Aquila (IA)	---	—	---	12/01-A	4.3 (I,B)
2/28/03	Madison Gas and Electric (WI)	9.71 (G)	12.30	55.42	12/03-A	6.8
3/7/03	Rochester Gas & Electric (NY)	8.11	9.96	41.40	6/03-A	5.5
3/12/03	Aquila Networks-MGU (MI)	---	11.40	—	12/03	8.4 (I,B)
3/20/03	Wisconsin Public Service (WI)	9.24 (G)	12.00	55.00	12/03-A	-1.2
2003	***1ST QUARTER AVERAGES/TOTAL***	**8.97**	**11.38**	**50.69**		**35.9**
	OBSERVATIONS	**4**	**5**	**4**		**6**
4/3/03	Wisconsin Power & Light (WI)	9.04 (G)	12.00	51.72	12/03-A	3.6
5/2/03	SEMCO Energy Gas (MI)	---	11.40	---	12/03	3.3 (B)
5/15/03	Entergy New Orleans (LA)	---	---	—	—	11.8 (B)
5/15/03	Interstate Power and Light (IA)	9.03	11.05	47.84 (U)	12/01-A	13.3 (I)
6/26/03	Public Service of Colorado (CO)	9.20	11.00	51.40	12/01-A	-17.8 (B)
2003	***2ND QUARTER AVERAGES/TOTAL***	**9.09**	**11.36**	**50.32**		**14.2**
	OBSERVATIONS	**3**	**4**	**3**		**5**
7/1/03	Citizens Utilities (AZ)	—	11.00	—	12/01-YE	15.2 (B)
7/29/03	Peoples Natural Gas (MN)	9.93	11.71	49.99	12/00-A	5.0 (I,B)
8/22/03	Northwest Natural Gas (OR)	8.62	10.20	49.50	9/04-A	13.9 (B,Z)
'/03	Arkansas Western Gas (AR)	6.74	9.90	35.20 *	6/02-YE	4.1 (B)
..17/03	ONEOK (KS)	---	---	---	—	45.0 (B)
9/25/03	Avista Corp. (OR)	8.88	10.25	48.25	12/02-A	6.3 (B)
2003	***3RD QUARTER AVERAGES/TOTAL***	**8.54**	**10.61**	**45.74**		**89.5**
	OBSERVATIONS	**4**	**5**	**4**		**6**
10/17/03	AmerenCILCO (IL)	8.16	10.54	48.54	12/01-YE	9.1
10/22/03	Orange & Rockland Utilities (NY)	---	---	---	10/04-A	23.6 (B,Z)
10/22/03	AmerenCIPS (IL)	8.33	10.71	44.44	6/02-YE	7.2
10/22/03	AmerenUE (IL)	8.24	10.46	52.70	6/02-YE	1.9
10/30/03	North Carolina Natural Gas (NC)	9.27	11.00	51.14	9/02-YE	21.0 (B)
10/31/03	Boston Gas (MA)	9.08	10.20	50.00	12/02-YE	19.7
10/31/03	Washington Gas (MD)	8.61	10.75	51.49	12/02-YE	2.9
11/10/03	Washington Gas (DC)	8.42	10.60	50.30	9/02-YE	5.4
12/9/03	Delmarva Power & Light (DE)	7.81	10.50	45.87	9/02	7.8 (I,B)
12/18/03	Washington Gas (VA)	8.44	10.50	50.96	12/01-YE	9.9 (I)
12/19/03	Wisconsin Power & Light (WI)	9.50 (G)	12.00	60.27	12/04-A	-0.4
12/19/03	Wisconsin Public Service (WI)	9.20 (G)	12.00	56.00	12/04-A	8.9
12/23/03	National Fuel Gas Distribution (PA)	---	---	---	9/03-YE	3.5 (B)
2003	***4TH QUARTER AVERAGES/TOTAL***	**8.64**	**10.84**	**51.06**		**120.5**
	OBSERVATIONS	**11**	**11**	**11**		**13**
.3	***FULL-YEAR AVERAGES/TOTAL***	**8.75**	**10.99**	**49.93**		**260.1**
	OBSERVATIONS	**22**	**25**	**22**		**30**

TELEPHONE UTILITY DECISIONS

There were no ROE or ROR authorizations for telecommunications companies in 2002 or 2003.

Date	Company (State)	Amt. $ Mil.
2/28/02	Verizon District of Columbia (DC)	-1.8
2002	*1ST QUARTER TOTAL*	1.8
	OBSERVATIONS	1
5/31/02	Central Telephone (NV)	43.5
6/19/02	Ameritech Illinois (IL)	-24.0
2002	*2ND QUARTER TOTAL*	19.5
	OBSERVATIONS	2
7/17/02	Verizon Maryland (MD)	-13.6
2002	*3RD QUARTER TOTAL*	-13.6
	OBSERVATIONS	1
2002	*4TH QUARTER TOTAL*	0.0
	OBSERVATIONS	0
2002	*FULL-YEAR TOTAL*	7.7
	OBSERVATIONS	4
2003	*1ST QUARTER TOTAL*	0.0
	OBSERVATIONS	0
5/21/03	Verizon North/Verizon South (IL)	-27.6 (B,Z)
2003	*2ND QUARTER TOTAL*	-27.6
	OBSERVATIONS	1
8/12/03	Verizon Northwest (WA)	-35.0
2003	*3RD QUARTER TOTAL*	-35.0
	OBSERVATIONS	1
2003	*4TH QUARTER TOTAL*	0.0
	OBSERVATIONS	0
2003	*FULL-YEAR TOTAL*	-62.6
	OBSERVATIONS	2

FOOTNOTES

A- Average
B- Order followed stipulation or settlement by the parties. Decision particulars not necssarily precedent-setting or specifically adopted by the regulatory body.
E- Estimated
G- Return on capital
Hy- Hypothetical
I- Interim rates implemented prior to the issuance of final order, normally under bond and subject to refund.
R- Revised
U- Double leveraged capital structure utilized.
YE- Year-end
Z- Rate change to be implemented in multiple steps.
* Capital structure includes cost-free items or tax credit balances at the overall rate of return.

(1) Data shown was utilized by the Illinois Commerce Commission to set delivery service prices for customers who select alternative generation suppliers. Customers who do not select an alternative supplier continue to pay the full bundled rate established in accordance with the state's restructuring law.
(2) 12% ROE includes a 25 basis point bonus for the company's service quality.
(3) Base rates are to be reduced 2.5% on 7/1/03, an additional 2.75% on 7/1/04, up to an additional 2.75% on 7/1/05, and up to an additional 2% on both 7/1/06 and 7/1/07.
(4) ROE actually authorized was 5.75%, as a 525 basis point penalty imposed in 1997 was not removed. In 1997, the Board placed the company on "regulatory probation" upon finding a "long and persistent record of misconduct and mismanagement."
(5) Rates to be reduced $21.7 million effective September 1, 2003 and an additional $13.5 million on September 1, 2005.
(6) Electric revenue requirement reduction. PSC changed an accounting amortization schedule to allow electric rates to remain unchanged.
(7) Return parameters established in proceeding to set delivery services tarrifs, which apply only to customers who select an alternative supplier of generation service.
(8) Rate changes include distribution rates and various restructuring related rate changes.
(9) Transmission and distribution rates only
(10) Company authorized to increase rates by 1.9% effective 1/1/05 and 0.9% effective 1/1/06, if the increases are supported by cost-of-service schedules.
1) Rate base valued as of 3/31/01.
2) $23,000 rate increase authorized.

Dennis Sperduto

Regulatory Research Associates, Inc.
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Regulatory Study
July 8, 2004

MAJOR RATE CASE DECISIONS--JANUARY-JUNE 2004

For the first six months of 2004, the average electric equity return authorization by state commissions was 10.63% (eight determinations), down modestly from the 10.97% average in calendar-2003. The average gas equity return authorization for the first two quarters of 2004 was 10.84% (seven determinations), down slightly from the 10.99% average in calendar-2003. During the first half of 2004, there was one telecommunications equity return authorization, 10%.

In recent years there have been relatively few equity return determinations. The reasons include: industry restructuring/intensifying competition; more efficient utility operations; technological improvements; relatively low inflation and interest rates; accelerated depreciation/amortization programs; the increased utilization of "black box" settlements; and, the use of performance, or price-based, regulation. As the number of equity return determinations has declined, the average authorized return now has less of a relationship to the return that the typical electric, gas, or telecommunications company has an opportunity to earn. In addition, electric industry restructuring in many states has led to the unbundling of rates, with commissions authorizing return and revenue requirement parameters for distribution operations only, thus complicating data comparability. The tables included in this study are extensions of those contained in the January 22, 2004 Regulatory Study entitled *Major Rate Case Decisions--January 2002-December 2003--Supplemental Study*. Refer to that report for information concerning individual rate case decisions that were rendered in 2002 and 2003.

The table on page 2 shows annual average equity returns authorized since 1994, and by quarter since 1998, in major electric, gas, and telecommunications rate decisions, followed by the number of determinations during each period. The tables on page 3 present the composite industry data for items in the chronology of this and earlier reports, summarized annually since 1994, and quarterly for the most recent six quarters. The individual electric, gas, and telecommunications cases decided in the first six months of 2004 are listed on pages 4 and 5, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return (ROR), return on equity (ROE), and percentage of common equity in the adopted capital structure. Next we show the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base, and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time decisions were rendered. A case is generally considered "major" if the rate change initially requested was $5 million or greater, or the authorized rate change was at least $3 million. Gas rate requests that are considered in conjunction with major electric requests are recorded and reported as individual cases, regardless of size.

Average Equity Returns Authorized January 1994 - June 2004

(Return Percent - No. of Observations)

	Period	Electric Utilities	Gas Utilities	Telephone Utilities
1994	Full Year	11.34 (31)	11.35 (28)	11.81 (11)
1995	Full Year	11.55 (33)	11.43 (16)	12.08 (8)
1996	Full Year	11.39 (22)	11.19 (20)	11.74 (4)
1997	Full Year	11.40 (11)	11.29 (13)	11.56 (5)
1998	1st Quarter	11.31 (4)	--- (0)	11.30 (1)
	2nd Quarter	12.20 (1)	11.37 (3)	— (0)
	3rd Quarter	11.80 (2)	11.41 (3)	— (0)
	4th Quarter	11.83 (3)	11.69 (4)	— (0)
1998	Full Year	11.66 (10)	11.51 (10)	11.30 (1)
1999	1st Quarter	10.58 (4)	10.82 (3)	13.00 (1)
	2nd Quarter	10.94 (4)	10.82 (3)	— (0)
	3rd Quarter	10.63 (8)	— (0)	— (0)
	4th Quarter	11.08 (4)	10.33 (3)	— (0)
1999	Full Year	10.77 (20)	10.66 (9)	13.00 (1)
2000	1st Quarter	11.06 (5)	10.71 (1)	11.50 (1)
	2nd Quarter	11.11 (2)	11.08 (4)	— (0)
	3rd Quarter	11.68 (2)	11.33 (5)	11.25 (1)
	4th Quarter	12.08 (3)	12.50 (2)	— (0)
J00	Full Year	11.43 (12)	11.39 (12)	11.38 (2)
2001	1st Quarter	11.38 (2)	11.16 (4)	— (0)
	2nd Quarter	10.88 (2)	10.75 (1)	— (0)
	3rd Quarter	10.78 (8)	— (0)	— (0)
	4th Quarter	11.50 (6)	10.65 (2)	— (0)
2001	Full Year	11.09 (18)	10.95 (7)	— (0)
2002	1st Quarter	10.87 (5)	10.67 (3)	— (0)
	2nd Quarter	11.41 (6)	11.64 (4)	— (0)
	3rd Quarter	11.06 (4)	11.50 (3)	— (0)
	4th Quarter	11.20 (7)	10.78 (11)	— (0)
2002	Full Year	11.16 (22)	11.03 (21)	— (0)
2003	1st Quarter	11.47 (7)	11.38 (5)	— (0)
	2nd Quarter	11.16 (4)	11.36 (4)	— (0)
	3rd Quarter	9.95 (5)	10.61 (5)	— (0)
	4th Quarter	11.09 (6)	10.84 (11)	— (0)
2003	Full Year	10.97 (22)	10.99 (25)	— (0)
2004	1st Quarter	11.00 (3)	11.10 (4)	10.00 (1)
	2nd Quarter	10.40 (5)	10.50 (3)	— (0)
2004	Year-To-Date	10.63 (8)	10.84 (7)	10.00 (1)

Electric Utilities--Summary Table*

	Period	ROR %	ROE %	Eq. as % Cap. Struc.	Amt. $ Mil.
1994	Full Year	9.29 (30)	11.34 (31)	45.15 (30)	1,116.9 (40)
1995	Full Year	9.44 (30)	11.55 (33)	45.90 (30)	455.7 (43)
1996	Full Year	9.21 (20)	11.39 (22)	44.34 (20)	-5.6 (38)
1997	Full Year	9.16 (12)	11.40 (11)	48.79 (11)	-553.3 (33)
1998	Full Year	9.44 (9)	11.66 (10)	46.14 (8)	-429.3 (31)
1999	Full Year	8.81 (18)	10.77 (20)	45.08 (17)	-1,683.8 (30)
2000	Full Year	9.20 (12)	11.43 (12)	48.85 (12)	-291.4 (34)
2001	Full Year	8.93 (15)	11.09 (18)	47.20 (13)	14.2 (21)
2002	Full Year	8.72 (20)	11.16 (22)	46.27 (19)	-475.4 (24)
2003	1st Quarter	9.07 (6)	11.47 (7)	49.94 (5)	48.2 (7)
	2nd Quarter	9.07 (4)	11.16 (4)	49.46 (4)	116.2 (5)
	3rd Quarter	8.22 (5)	9.95 (5)	46.09 (5)	69.6 (5)
	4th Quarter	9.07 (5)	11.09 (6)	52.17 (5)	210.4 (5)
2003	Full Year	8.86 (20)	10.97 (22)	49.41 (19)	444.4 (22)
2004	1st Quarter	8.94 (3)	11.00 (3)	44.94 (3)	-711.2 (5)
	2nd Quarter	7.64 (5)	10.40 (5)	45.27 (5)	627.0 (10)
2004	Year-To-Date	8.13 (8)	10.63 (8)	45.15 (8)	-84.2 (15)

Gas Utilities--Summary Table*

	Period	ROR %	ROE %	Eq. as % Cap. Struc.	Amt. $ Mil.
1994	Full Year	9.51 (32)	11.35 (28)	48.12 (27)	422.9 (42)
1995	Full Year	9.64 (16)	11.43 (16)	49.98 (15)	-61.5 (31)
1996	Full Year	9.25 (23)	11.19 (20)	47.69 (19)	193.4 (34)
1997	Full Year	9.13 (13)	11.29 (13)	47.78 (11)	-82.5 (21)
1998	Full Year	9.46 (10)	11.51 (10)	49.50 (10)	93.9 (20)
1999	Full Year	8.86 (9)	10.66 (9)	49.06 (9)	51.0 (14)
2000	Full Year	9.33 (13)	11.39 (12)	48.59 (12)	135.9 (20)
2001	Full Year	8.51 (6)	10.95 (7)	43.96 (5)	114.0 (11)
2002	Full Year	8.80 (20)	11.03 (21)	48.29 (18)	303.6 (26)
2003	1st Quarter	8.97 (4)	11.38 (5)	50.69 (4)	35.9 (6)
	2nd Quarter	9.09 (3)	11.36 (4)	50.32 (3)	14.2 (5)
	3rd Quarter	8.54 (4)	10.61 (5)	45.74 (4)	89.5 (6)
	4th Quarter	8.64 (11)	10.84 (11)	51.06 (11)	120.5 (13)
2003	Full Year	8.75 (22)	10.99 (25)	49.93 (22)	260.1 (30)
2004	1st Quarter	8.52 (4)	11.10 (4)	45.61 (4)	82.3 (7)
	2nd Quarter	8.24 (3)	10.50 (3)	46.98 (3)	95.9 (9)
2004	Year-To-Date	8.40 (7)	10.84 (7)	46.20 (7)	178.2 (16)

Telephone Utilities--Summary Table*

	Period	ROR %	ROE %	Eq. as % Cap. Struc.	Amt. $ Mil.
1994	Full Year	9.91 (12)	11.81 (11)	57.46 (11)	-236.6 (16)
1995	Full Year	9.81 (8)	12.08 (8)	55.02 (7)	-264.0 (14)
1996	Full Year	9.65 (2)	11.74 (4)	56.00 (2)	-348.2 (11)
1997	Full Year	9.57 (5)	11.56 (5)	55.84 (5)	-154.4 (7)
1998	Full Year	9.37 (1)	11.30 (1)	52.00 (1)	-323.3 (13)
1999	Full Year	11.34 (1)	13.00 (1)	66.90 (1)	-570.1 (19)
2000	Full Year	9.52 (2)	11.38 (2)	56.59 (2)	-390.4 (14)
2001	Full Year	9.61 (1)	— (0)	— (0)	-130.0 (8)
2002	Full Year	— (0)	— (0)	— (0)	7.7 (4)
2003	1st Quarter	— (0)	— (0)	— (0)	— (0)
	2nd Quarter	— (0)	— (0)	— (0)	-27.6 (1)
	3rd Quarter	— (0)	— (0)	— (0)	-35.0 (1)
	4th Quarter	— (0)	— (0)	— (0)	— (0)
2003	Full Year	— (0)	— (0)	— (0)	-62.6 (2)
2004	1st Quarter	8.02 (1)	10.00 (1)	44.18 (1)	3.1 (1)
	2nd Quarter	— (0)	— (0)	— (0)	— (0)
2004	Year-To-Date	8.02 (1)	10.00 (1)	44.18 (1)	3.1 (1)

* Number of observations each period indicated in parentheses.

ELECTRIC UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
3/04	Madison Gas and Electric (WI)	9.37 (G)	12.00	55.91	12/04-A	11.7
2/18/04	United Illuminating (CT)	—	—	—	—	5.2 (B)
2/26/04	Pacific Gas and Electric (CA)	—	—	—	—	-799.0 (B)
3/2/04	PacifiCorp (WY)	8.42	10.75	44.95	9/02-YE	22.9
3/26/04	Nevada Power (NV)	9.03	10.25	33.97	5/03-YE	48.0
2004	***1ST QUARTER AVERAGES/TOTAL***	**8.94**	**11.00**	**44.94**		**-711.2**
	OBSERVATIONS	**3**	**3**	**3**		**5**
4/13/04	Aquila-MPS (MO)	—	—	—	—	14.5 (B)
4/13/04	Aquila-L&P (MO)	—	—	—	—	3.3 (B)
5/5/04	Wisconsin Electric Power (WI)	—	—	—	12/04-A	59.0
5/18/04	PSI Energy (IN)	7.30	10.50	44.44 *	9/02-YE	107.3
5/20/04	Rochester Gas & Electric (NY)	—	—	—	—	7.4 (1)
5/25/04	Idaho Power (ID)	7.85	10.25	45.97	12/03-A	25.3
5/27/04	Pacific Gas & Electric (CA)	—	—	—	12/03-A	274.0 (B)
5/27/04	Sierra Pacific Power (NV)	9.26	10.25	35.77	7/03-YE	46.7 (B)
6/30/04	Kentucky Utilities (KY)	7.00 (G)	10.50	51.58	9/03-YE	46.1 (B,2)
6/30/04	Louisville Gas and Electric (KY)	6.79 (G)	10.50	48.60	9/03-YE	43.4 (B,3)
2004	***2ND QUARTER AVERAGES/TOTAL***	**7.64**	**10.40**	**45.27**		**627.0**
	OBSERVATIONS	**5**	**5**	**5**		**10**
2004	***YEAR-TO-DATE AVERAGES/TOTAL***	**8.13**	**10.63**	**45.15**		**-84.2**
	OBSERVATIONS	**8**	**8**	**8**		**15**

GAS UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/13/04	AmerenUE (MO)	—	—	—	—	13.0 (B)
1/13/04	Madison Gas and Electric (WI)	9.37 (G)	12.00	55.91	12/04-A	1.0
1/13/04	Public Service Co. of New Mexico (NM)	8.16	10.25	47.77	9/02-YE	22.0 (B)
1/21/04	Aquila (NE)	—	—	—	—	6.2 (I,B)
2/9/04	City Gas Co. of Florida (FL)	7.36	11.25	36.77 *	9/04-A	6.7 (I)
2/19/04	Wisconsin Gas (WI)	—	—	—	12/04-A	26.0
3/16/04	Southwest Gas (CA)	9.17	10.90	42.00	12/03-A	7.4 (4)
2004	***1ST QUARTER AVERAGES/TOTAL***	**8.52**	**11.10**	**45.61**		**82.3**
	OBSERVATIONS	**4**	**4**	**4**		**7**
4/5/04	Interstate Power and Light (MN)	9.05	11.00	47.15	12/02-A	0.2 (I)
4/22/04	Aquila Networks-MPS (MO)	—	—	—	—	2.6 (B)
4/22/04	Aquila Networks-L&P (MO)	—	—	—	—	0.8 (B)
5/20/04	Rochester Gas & Electric (NY)	—	—	—	—	7.2 (1)
5/25/04	TXU-Gas (TX)	8.26	10.00	49.80	12/02-YE	12.0
5/27/04	Pacific Gas & Electric (CA)	—	—	—	12/03-A	52.0 (B)
6/23/04	Northwest Natural Gas (WA)	—	—	—	—	3.5 (B)
6/30/04	Southern Indiana Gas and Electric (IN)	7.41	10.50 (B)	44.00 *	9/03-YE	5.7 (B)
6/30/04	Louisville Gas and Electric (KY)	—	—	—	—	11.9 (B)
2004	***2ND QUARTER AVERAGES/TOTAL***	**8.24**	**10.50**	**46.98**		**95.9**
	OBSERVATIONS	**3**	**3**	**3**		**9**
04	***YEAR-TO-DATE AVERAGES/TOTAL***	**8.40**	**10.84**	**46.20**		**178.2**
	OBSERVATIONS	**7**	**7**	**7**		**16**

TELEPHONE UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/29/04	CenturyTel of North West Arkansas (AR)	8.02	10.00	44.18	6/02-YE	3.1 (B)
2004	***1ST QUARTER AVERAGES/TOTAL***	**8.02**	**10.00**	**44.18**		**3.1**
	OBSERVATIONS	**1**	**1**	**1**		**1**
2004	***2ND QUARTER AVERAGES/TOTAL***	**—**	**—**	**—**		**—**
	OBSERVATIONS	**0**	**0**	**0**		**0**
2004	***YEAR-TO-DATE AVERAGES/TOTAL***	**8.02**	**10.00**	**44.18**		**3.1**
	OBSERVATIONS	**1**	**1**	**1**		**1**

FOOTNOTES

A- Average
B- Order followed stipulation or settlement by the parties. Decision particulars not necssarily precedent-setting or specifically adopted by the regulatory body.
G- Return on capital
I- Interim rates implemented prior to the issuance of final order, normally under bond and subject to refund.
YE- Year-end
* Capital structure includes cost-free items or tax credit balances at the overall rate of return.
(1) Electric increase represents implementation of a Retail Access Surcharge for recovery of retail access credits provided to customers who select an alternative generation supplier. Gas increase represents a gas Merchant Function Charge designed to recover indirect gas costs.
(2) Indicated rate case parameters support a $49.8 million electric increase.
(3) Indicated rate case parameters support a $45.6 million electric increase.
(4) Represents the combined increase authorized the company's southern California and northern California rate jurisdictions.

Dennis Sperduto

Commission Data Request 1-97

Request:

Please provide the evidence in this docket that provides the basis for the statement that "the Parties agree that Rates B-32 and B-62 as set forth in Exhibit 2, are cost-based, just and reasonable, and not unduly discriminatory under G.L. 39-2-1.4(b).."

Response:

The parties to the Settlement have agreed that the rate class revenue shown in Exhibit 3 to the Settlement represents a fair and reasonable allocation of class cost responsibility in the overall context of the Settlement. The basis for each party's conclusion may differ, but may include the respective party's view of the revenue neutral allocated cost of service study presented by the Company in RIPUC Docket No. 3610, as well as each party's understanding of alternative cost of service methodologies that have been accepted by the Commission in other dockets.

Because the Company will generally incur the same distribution cost to serve a backup service customer as an all-requirements customer with similar maximum load characteristics, the proposed backup service rates have been designed to provide comparable cost recovery from customers that place similar demands on the distribution system, and to ensure that the revenue contribution from the class will not be significantly affected by a customer's choice whether to install on-site generation. Therefore the proposed distribution rates do not discriminate against like customers whose cost to serve is essentially the same.

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

Commission Data Request 1-98

Request:

Please explain in detail, every cost associated with serving a back-up customer and what Narragansett must do to ensure service and reliability to the customer.

Response:

A back-up service customer requesting instantaneous, firm back-up service from the distribution company imposes on the utility the obligation to have the necessary facilities standing by to serve the peak load at the customer's facility at any time. This obligation is the same one the utility bears in serving a non-generating, or "all-requirements," customer. Indeed, the very name "standby" or "back-up" service denotes that the utility is being asked to do something – i.e., to standby and be ready to serve the customer's load at any time, including at times of peak loading on the local distribution facilities. Thus, the costs incurred by the Company to provide back-up service do not differ from the costs the Company incurs in serving all-requirements customers (with the exception of any additional relaying or protection equipment costs that may be associated with serving a customer with on-site generation).

Because the costs of the local distribution system needed to serve an on-site generating customer taking firm back-up do not differ from the costs of serving a similarly sized all-requirements customer, fairness demands that each customer contribute equitably to support the distribution system that serves them. If firm, instantaneous back-up customers did not support their share of the distribution system investment, and those costs had to be recovered from other, non-generating customers, the rates for non-generating customers would *increase* as the result of the decision of other customers to install on-site generation, even though the non-generating customers are not using or relying on the system any more than they did previously. In that case, the standby customer would be receiving the utility's commitment to back-up the customer's generation for less, subsidized by other customers.

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

Commission Data Request 1-99

Request:

Some rate increases are proposed to be transitioned into full effect over a period of time as a result of the elimination of rate classes. On a one page table, please identify each rate subject to transition, the manner in which the transition will be implemented, the amount of costs that would be recovered from the class absent the transition period, and from where the lost revenues will be collected during each year of the transition.

Response:

The table below indicates each rate class that the Company proposes to eliminate at the end of the rate freeze period, the phase-in period, the revenue that each class would be contributing if they were to be transferred to their respective ultimate rate class on the effective date of the settlement, and the rate class from which the reduced revenues will be recovered during the phase-in period. Also indicated is the page number from Exhibit 5 where the specific calculation for each rate class is located. For further explanation of the phase-in procedure, see the response to Commission Data Request 1-18.

Rate Class	Phase-in Period	Revenue–Final Year	Revenue Recovery	Exhibit 5 Reference
R-02	5-year, rates increase by fixed amount each year	$173,906	Revenue recovered from Rate C-06	Page 9
T-06	5-year, rates increase by fixed amount each year	$305,358 (C-06) $307,203 (A-16)	Revenue recovered from Rates C-06 and A-16	Page 9 and Page 6
E-30	5-year, rates increase by fixed amount each year	$60,261	Revenue recovered from Rate A-16	Page 6
Auxiliary Service	5-year, rates increase by fixed amount each year	$367,920	Revenue recovered from Rate G-32/B-32	Page 17

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

Commission Data Request 1-100

Request:

Please explain power factor so that a non-engineer could explain it to a member of the public.

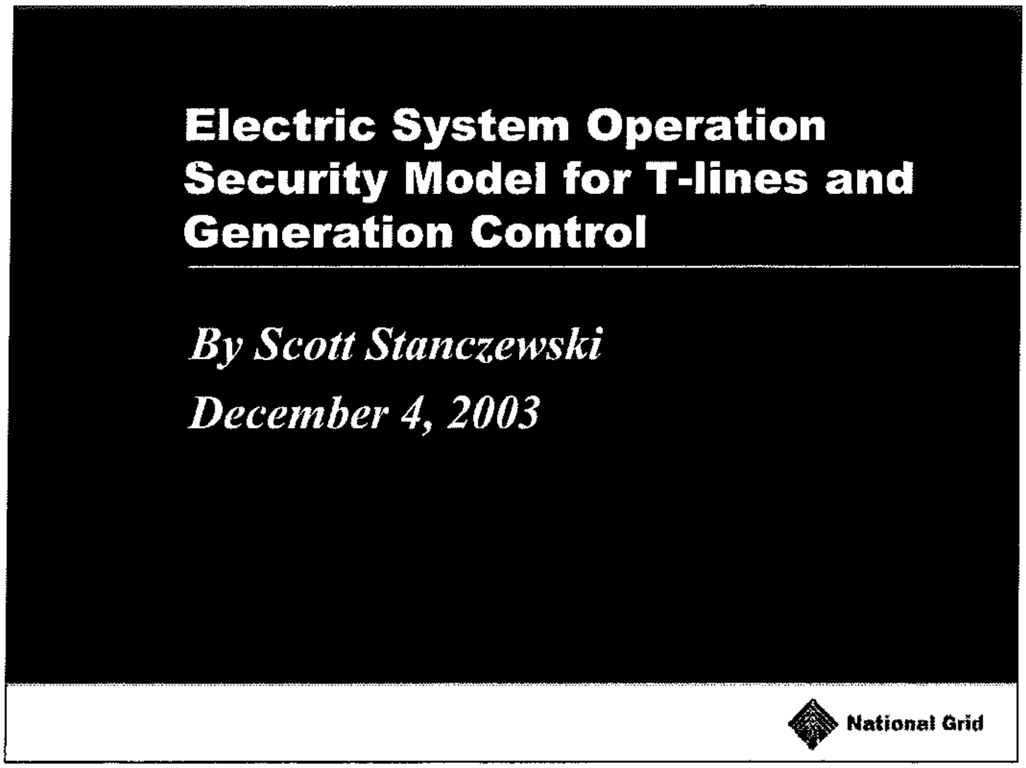
Response:

Power factor is a measure of efficiency. It is the ratio of the real power (watts) used by a customer's electrical equipment to the total apparent power (volt-amperes) supplied to the equipment. More simply, it is a ratio that compares how much power is required to get work done with how much power must actually be supplied to get that work done. The ideal power factor measurement is 1 (or 100%). The lower a power factor measurement is, the greater the demands placed on the electrical system to deliver the same amount of real power. The negative impacts of low system power factor include:

- Reduced capacity to provide real power
- Increased losses
- Poor voltage control

Attached to this response is a copy of an internal presentation prepared by personnel of a Narragansett affiliate company. This presentation provides further basic explanation of the alternating current power system and reactive power.

Prepared by or under the supervision of: Alan T. LaBarre



Good afternoon. My name is Scott Stanczewski and today I will be talking about transmission system operation and planning criteria. I am a senior engineer in the transmission planning department responsible for the 69kV and above transmission system in the western division.

Basics

- Basic Engineering Measurements

  1. Volts
  2. Amps
  3. Power

National Grid

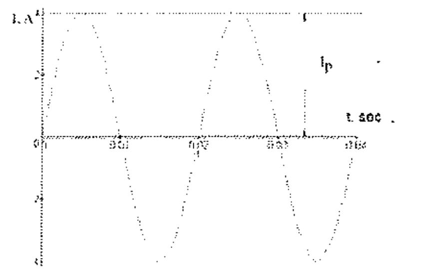
First, lets talk a little about fundamental engineering measurements vital to planning and operating the system. Fundamental engineering measurements are volts, amps, and power. All values are sinusoidal in nature resulting in an associated angle with each value but the physics is still the same as simple DC! Volts and amps are relatively straight forward but the concept of real and reactive power is sometimes a little difficult to understand.

AC Circuit Theory

It's all about Angles!!!!

In simplest terms:

- As a conductor pass through a magnetic field, a current is induced into the conductor.
- Magnitude of the current is greatest as it passes through the greatest concentration of magnetic flux

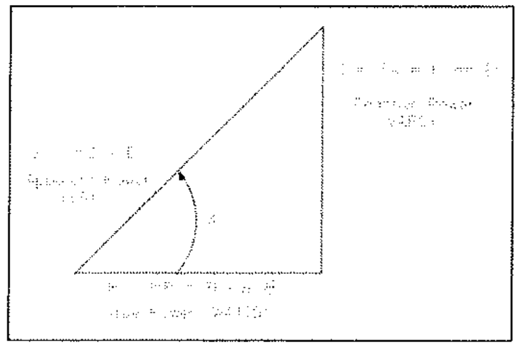


National Grid

From ohm's law, P=VI. Since these values are sine waves that are usually out of phase with each other. The result of the power equation is KVA or apparent power with an associated phase angle.

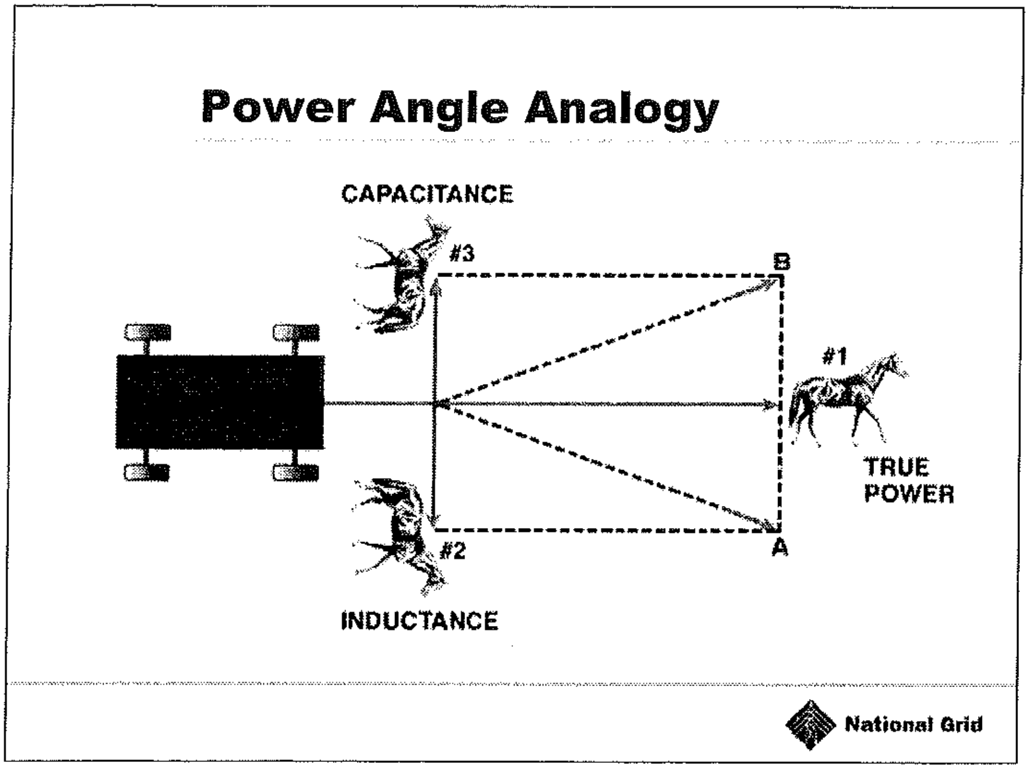
Power Relationships

- Power Triangle
  - P=V*I from ohm's law
    - So why is this different than DC?



National Grid

Taking the angle into account, we can break apparent power into two components, real and reactive. Real power is the power used by resistive loads. Reactive power is the power used by an induction motor for magnetizing current in the rotor. Reactive power can be supplied by generation or by capacitor banks. Line loading can be decreased through power factor correction at the load.



An analogy will enhance understanding. Imagine a farm wagon on a country road to which three horses were hitched, as shown in this illustration. The one in the middle is pulling straight down the road. We'll call him "True Power" because all his effort is in the direction that work should be done. The one on the right #2 doesn't contribute an ounce of pull in the desired direction called inductance. The third horse, about the size of #2, is 180 degrees out of phase with #2 and contributes nothing to forward motion either.

For the moment we'll forget #3. If only #1 and #2 were pulling, the wagon would go in the direction of the dotted line A. Notice the length of that line is greater than the line to #1. The direction and length of A might well be called "apparent power" and happens to be the hypotenuse (or diagonal) of a right angle triangle.

If #2 were left at home, then #1 and #3 in combination would pull towards B and the length of that line would also be "apparent power." If all three were on the job, #2 and #3 would cancel one another, and the only useful animal is #1.

An AC circuit always has all three forces in the picture in varying line segment lengths. We should not complain about inductance because it is always present in every magnetic circuit and always works at a 90 degree angle with True Power. After all, without magnetism we would have no motors or transformers.

As you can see, True power is decreased as capacitance or inductance is increased.

Reactive Power

What uses it?

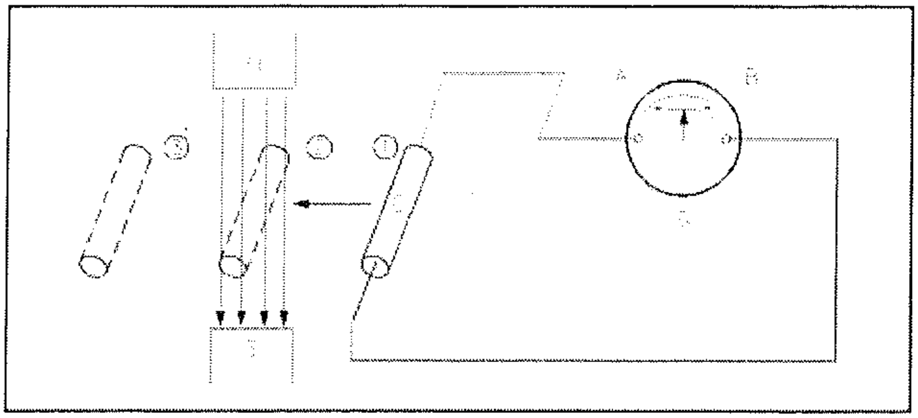
- Motor loads
- Conductor losses
- Harmonics
- Transformers

What Produces it?

- Generators
- Station Equipment
- Long Transmission Lines

National Grid

Magnetic Flux and Current Flow



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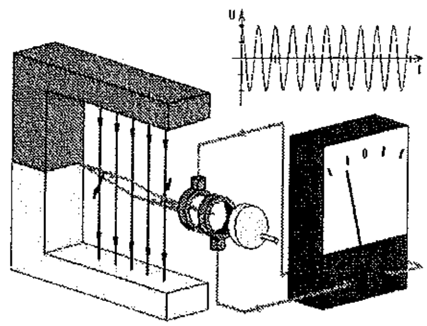
Simple Generator Model



As the armature rotates through the magnetic field, a current is induced, when the rotation is at 180 degrees, the magnetic poles are reversed which reverses the current flow.

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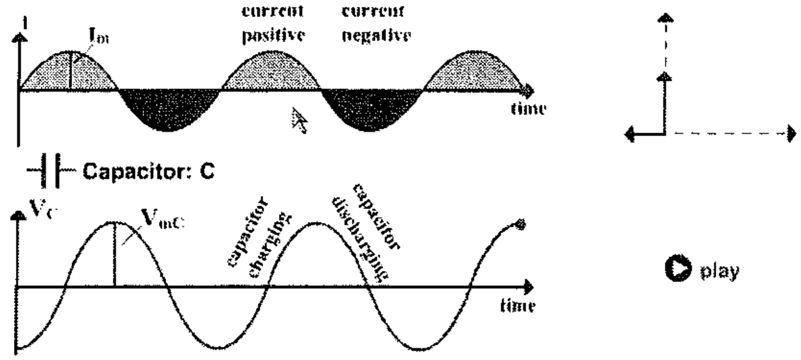
Phase shift between voltage and current

Current leads voltage by 90 degrees



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By introducing reactive components into the system, we can shift the phase angle between voltage and current. As in the case of this capacitor, there is a time lag between charging and discharging causing the phase difference. The same is for an inductive device such as a motor which would absorb reactive power.

Generation

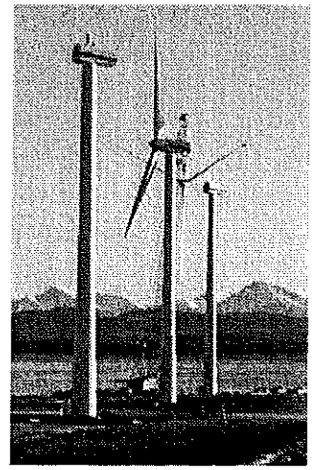
- Synchronous
  - Large scale generation
  - Major source of reactive power
  - Uses internal excitation to vary phase angle between voltage and current
  - Can be run in stand-alone mode
  - Speed of machine determines system frequency
  - Increased current draw onto system causes EMF in rotor to incease slowing down machine – more mechanical input must be added to keep machine rotation constant

National Grid

Synchronous generation provides the base source of power on the transmission network. Without these units, power could not be restored in the event of a catastrophic blackout. Vars are produced by varying the excitation field in the generator. More excitation varies the power angle.

Generation

- **Asynchronous**
  - **Small scale generation**
  - **Induction machine**
  - **Uses electric grid for excitation.**
  - **Cannot be run in stand-alone mode**
  - **Speed of machine determines power output**
  - **Rotating electric field induces current flow into the rotor**
  - **More rotational speed increases output**
  - **No var output capability**



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Asynchronous generators are predominant in wind turbine applications where rotational speed tends to be variable in nature. The generator is excited through the electric grid. He resulting EMF in the machine rotates with the frequency of the system. The faster the rotor is turned, the more EMF each conductor in the rotor passes through creating more current flow out of the machine. Since the current used for excitation is in phase with the system, var flow will always be lagging or into the machine. Capacitors will typically be used to correct machine power factor to unity. Asynchronous generators work on the same principle as a induction motor. Machine works on motor slip principles.

Commission Data Request 1-101

Request:

Are the parties willing to amend Part 17(E) to state: "This Settlement is submitted on the condition that it be approved in full by the Commission, and on the further condition that if the Commission does not approve the Settlement in its entirety, the Settlement shall be deemed withdrawn and shall not constitute a part of the record in any proceeding or be used for any purpose unless the parties agree to Commission modifications.?" If not, please offer other language, or if you do not agree to any amendment of this Part, please explain why the Commission should not simply reject and dismiss the filing and act on each docket currently pending before the Commission regarding Narragansett Electric's rates.

Response:

At the prehearing conference on July 16, 2004, the Parties to the Settlement agreed to an amendment that adds "unless all parties agree to Commission modifications" to Section 17(E).

Prepared by or under the supervision of: Legal Department